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2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK

REPORT OF THE BOARD

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BACKGROUND

The 2006 Electricity Distribution Rates consultative involved several phases. The project was initiated by a letter from the Board to all distributors and other stakeholders dated June 16, 2004. In July 2004, Board staff met with stakeholders to discuss potential issues to be addressed in the process. The Board published a notice in the media inviting public participation and comment. A further issues meeting was held in September, and working groups were formed to begin drafting a rate handbook. The progress of the working groups was reported at subsequent general stakeholder meetings. The first draft of the rate handbook prepared by the working groups was posted on the Board's website in early December. After considering stakeholder comments, the working groups completed the second draft of the handbook, which was released on January 10, 2005 (the draft Handbook).

A more formal consultation was conducted by the Board to consider the product of the working group efforts. The first stage was an issues day, during which the Board determined the extent of the matters to be addressed in the rate handbook. After completion of the second draft, the Board received written evidence and heard from several expert witnesses on selected contentious issues. Subsequent to hearing from the experts, the Board received written submissions on many of the alternatives proposed in the draft Handbook.

As part of Issues Day, the Board provided some guidance to the participants respecting what it saw as the rational next steps in the evolution of ratemaking in Ontario following the production of the Electricity Distribution Rate Handbook for 2006. These steps included Board reviews of the methods underpinning cost allocation, depreciation rates and methodology, working capital, and the cost of capital and related issues.

In his letter to the industry dated March 9, 2005, the Chair of the Board confirmed and refined the Board's commitment to these reviews, and added the need for the Board to consider the implications of the implementation of new metering technology and other developments in the energy sector as it develops its ratemaking plans for subsequent years. This is an aggressive agenda, which requires a significant commitment from all participants if it is to be achieved within the current projected timeframe.

Each chapter of this Report corresponds to the same chapter in the Rate Handbook. The Board does not address every item in the Handbook in this Report. Generally speaking, if a consensus was developed in the working groups and was not opposed in the submissions, then that consensus is reflected in the Handbook. This Report will address the following items:

- issues for which a consensus was not reached
- any consensus position which was subsequently opposed in the submissions
- any areas where the Board has concluded that a material change is required to the consensus position.

Some additional modifications have been made to the Handbook in order to enhance its clarity. Those changes are not discussed in this report unless they are material.

CHAPTER 1: INTRODUCTION

Chapter 1 provides an overall introduction to the 2006 Handbook. The chapter outlines the components of the application and the filing dates. A number of proposals were made for additions or refinements.

Issues and Conclusions

The Association of Major Power Consumers of Ontario (AMPCO) proposed additional wording to emphasize that the Handbook relates to 2006 only and to summarize the further reviews in 2007 and 2008. The Consumers Council of Canada (CCC) expressed similar concerns. The Board agrees that the 2006 Handbook is for 2006 rates only, and the Introduction clearly says so. The Board has communicated its plans for 2007 and 2008 through a number of channels, including at the beginning of this Report, and will continue to communicate on these issues. The Board concludes that no additions to the 2006 Handbook in this respect are required.

Toronto Hydro appeared to suggest that the filing deadline for all applications should be delayed until the Handbook and the model are in "workable condition". CCC also expressed concerns about the filing deadline. Schools Energy Coalition (Schools) opposed any delay that would reduce the time available to process the applications. The Board is sensitive to concerns regarding the tight timeframes and the pressure that these place on stakeholders. However, the Board does not believe that delaying applications, pending further revisions to the Handbook, will provide an appropriate solution. Applicants will proceed on the basis of the Handbook and Model as they are released. If material revisions are subsequently required, the Board will deal with them in due course.

Hydro Ottawa proposed that a later filing deadline of September 1, 2005 be set for distributors filing on a forward test year basis. The Board agrees with Hydro Ottawa that a forward test year application will entail greater detail and more work on the part of the distributor. A forward test year application will also require greater effort on the part of the Board and stakeholders to evaluate. The Board will therefore not set a later filing deadline for forward test year applications in the Handbook.

The Board has determined that a single filing deadline for all distributors will not be the most efficient for purposes of processing the applications in a timely manner. For that reason, the Board has decided that it will prescribe three filing deadlines, generally requiring earlier filings from larger distributors. The Handbook contains the details of the filing schedule.

Schools proposed extensive additions related to consultation prior to filing, provision of applications to stakeholders, and the role of stakeholders. Its proposals were opposed by a number of distributors on the grounds that they were unnecessary or that they were procedural and therefore not within the purpose of the Handbook. While the Board agrees with some of the sentiments expressed by Schools, in particular regarding cooperation between applicants and intervenors, the Board does not believe the Handbook is the appropriate place to articulate procedural expectations. The Handbook is a filing guideline; it is not a process guideline.

CHAPTER 2: DESCRIPTION OF THE APPLICATIONS

Chapter 2 of the Handbook provides a high level description of a distributor's application and identifies the major components of the application. Stakeholders made a number of proposals for additions or refinements.

Data Requirements and Data Aggregation

Of overall concern to distributors and stakeholders is the nature of the data that will be required to support an application. This issue arises in the context of a number of chapters and for that reason the Board has decided to address this issue at the beginning of the Handbook.

The Board, by letter dated March 23, 2005, has required each electricity distributor to correct, update and confirm the data filed as part of the Board's Reporting and Record-keeping Requirements (RRR) and use the confirmed trial balance data as the basis of its 2006 rate applications. In addition, as indicated in the Board's letter to the distributors and in Chapter 14 of this Report, the confirmed RRR data will be used in the comparator and cohort analysis. Once a distributor has updated and confirmed its RRR filings, the data will be sent back to the distributor in a format compatible with the 2006 EDR Model. The data can then be inserted directly into the trial balance sheets of the Model.

The question then arises as to whether the applications should be submitted with the cost information presented at the detailed trial balance level, or at a more aggregated level. The Draft Handbook contained two alternatives. Alternative 1 requires that the complete trial balance be filed, and Alternative 2 allows for the data to be reported in aggregated groupings.

Customer groups generally favoured more detailed filing. Energy Probe supported the filing of aggregated data for 2002 and 2003, but detailed data for 2004. CCC suggested that a further, brief stakeholder consultation should deal with the precise level of detailed information needed to balance accuracy and simplicity. London Property Management Association (LPMA) supported detailed filing because distributors may group their costs differently, making it difficult to compare the costs, and because maximum flexibility should be retained for cost allocation purposes in 2007.

Distributors supported a less detailed filing, because in their view the aggregate level of detail is sufficient to assess spending. Schools also agreed that aggregate data would be sufficient for the 2006 rate process.

Also under consideration is the number of years of data that will be required. Few submissions were received on this issue, although those who did make submissions supported the filing of three years of data.

Conclusions

The Board recognizes that a number of distributors have found compliance with the RRR to be challenging, and a number have failed to meet the RRR requirements. It is imperative that all distributors develop the capability to meet the requirements of this program, and that they do so now. This requirement places little additional burden on distributors whose filings have been compliant with the RRR program, but does require all to re-visit former filings with a view to ensuring unambiguous compliance. If the RRR filings are not confirmed, a distributor making a rate application will be required to identify and explain inconsistencies between the RRR filings and the rate application filings. This could delay processing of the application.

The Board agrees that three years of data is necessary for the rate applications, in order that unusual costs in 2004 or cost trends over time can be identified. The Board does not believe that the trial balance level of detail is necessary to be filed as part of the initial application, particularly as quite a number of specific distribution expense items are to be dealt with on the basis of detailed reporting. The Board has therefore concluded that the data will be presented in the application in an aggregated format.

Applicants will input the RRR data into the 2006 Rate Model, and the model will automatically aggregate the data. Appendix A of the Handbook identifies the specific trial balance accounts that will be aggregated in each line item. The Board will also require each distributor to file its audited financial statements for the years 2002, 2003 and 2004. If a distributor enters data into the model which differs in any way from the RRR data, other than as permitted in the Handbook, it must document and explain such differences, and provide a reconciliation to the RRR data. Similarly, if the data used in the model is inconsistent with the audited financial statements, a reconciliation must be provided.

Filing Requirements – Other Issues

Hydro One Networks Inc. (Hydro One) proposed specific wording to identify separately what will be required for a historical test year application and what will be required for a forward test year application. The Vulnerable Energy Consumers Coalition (VECC) supported this proposal and also indicated that the overall approach should be characterized as "cost of service". CCC suggested that the Board provide an example of an application that includes the required level of evidentiary detail for each of the filing alternatives (Tier 1, Tier 2, or a forward test year). CCC also suggested that the Board set out the level of detail required to support an application that departs from the Handbook.

Both Schools and VECC made submissions regarding electronic filings. VECC proposed that the models should be filed in "working form", not hard coded, and Schools submitted that spreadsheets should be filed on a "live" basis. Toronto Hydro expressed reservations about filing "live" spreadsheets and submitted that "read only" versions would be appropriate.

In her closing submission to the Panel, Board Counsel suggested a revised section 2.1.3 Compliance with Licence as follows:

> The description of the application should include a statement of whether the distributor has any special conditions in its licence, or if it is exempted from any specific conditions of its licence, that will affect the review of this application.

No parties opposed this revision.

Conclusions

While the Board understands the concerns of Hydro One and CCC, the Board does not believe that specifying forward test year requirements or identifying an example application will be of assistance. The required level of detail will by necessity vary from applicant to applicant, depending upon the nature and extent of the adjustments sought. What is sufficient in one case to support one set of adjustments, may not be sufficient in another case. Likewise, the level of detail required to support a forward test year application, or an application that deviates from the Handbook is difficult to specify precisely without knowing the nature of the deviation. Applicants must understand that each level of departure from the framework described in the Handbook requires further explanation and evidentiary support. The Board intends to continue to work with distributors so that they understand the requirements and can prepare their applications accordingly.

With respect to electronic filings and spreadsheets, the Board believes that the process will be furthered if the technical material is transparent to all participants. The Board therefore expects that spreadsheets will be filed in such a way that the logic is apparent and the calculations can be replicated. The 2006 rate model will use the RRR data as inputs and will perform a level of aggregation for purposes of generating the 2006 rate application. The model spreadsheets, which are filed, will not disclose the disaggregated data.

The Board will incorporate the revised section 2.1.3, as articulated by Board counsel, into the Handbook.

CHAPTER 3: TEST YEAR AND ADJUSTMENTS

Chapter 3 of the 2006 Handbook deals with two major areas of concern:

- the test year on which the filing is to be based, including the potential disclosure of material events in 2006, and
- the adjustments that may be permitted to the base test year.

Test Year Options

The Draft Handbook set out two filing options:

- a 2004 historical test year filing with mandatory "Tier 1" adjustments and additional optional "Tier 2" adjustments for eligible applicants
- a full 2006 forward test year filing.

In Board staff's closing submission to the Panel, it was noted that concerns had been expressed by smaller distributors about the complexity of the filing requirements, and, in particular, the mandatory Tier 1 adjustments. In response to these concerns, Board staff raised the possibility that the rate application process could be made less complex by permitting a rate application to be based on unadjusted 2004 data. This was not an alternative listed in the draft Handbook.

CCC and Schools opposed this option on the basis that a distributor would choose the option that is most advantageous to its shareholders. In their view, all distributors should be required to make mandatory Tier 1 adjustments. VECC supported the option, subject to inclusion of any mitigation requirements.

Enbridge Gas Distribution (Enbridge), Union Gas Limited (Union), VECC and LPMA supported the use of a forward test year, and submitted that the Board should move to a forward test year basis as soon as practical.

Conclusions

The Board agrees that a forward test year is the preferred approach to setting cost of service rates. However, the Board has determined that it must establish a practical approach to setting 2006 rates and that a historical test year should be the basis of the 2006 rate applications. The Board concludes that there is also merit in the option identified by Board staff. The Board believes that the concern expressed by Schools and CCC is misplaced. Many of the Tier 1 adjustments will result in upward pressure on rates. This is balanced by the requirement for a sound evidentiary basis to support any adjustment. It is probable that a distributor that opts for an unadjusted historical test year will do so because the expected increased revenue from an adjusted historical test year application does not warrant the cost involved in making such an application. Accordingly, an applicant will have four options:

- a 2004 historical test year, with no adjustments
- a 2004 historical test year, with Tier 1 adjustments
- a 2004 historical test year, with Tier 1 and Tier 2 adjustments
- a 2006 forward test year

If a distributor chooses to apply on an adjusted 2004 historical test year basis, it will be required to make all of the Tier 1 adjustments; it cannot pick and choose from amongst the adjustments. If an applicant chooses to apply for the Tier 2 optional adjustments, it will be required to make all the Tier 1 adjustments as well. If an applicant chooses to apply on a forward test year basis, it must supply substantial supporting material to justify its projected expenses and revenues. It is likely that a forward test year application will receive more scrutiny and take longer to process than a historical test year application.

Disclosure of Material Events Expected to Occur in 2006

The Draft Handbook presents two alternatives for the disclosure of material events expected to occur in 2006 that are identifiable, quantifiable and verifiable:

- Alternative 1: the applicant is obliged to disclose these events
- Alternative 2: the applicant is not obliged to disclose these events.

Most customer representatives submitted that a distributor should be obliged to disclose any material events expected to occur in 2006. In their view, the regulator should know all material circumstances, and there must be full disclosure on the public record. CCC, for example, submitted that if there is a predictable impact on 2006 then it should be reflected in rates.

Distributors submitted that disclosure should not be mandatory. In their view, disclosure of material events expected in 2006 is only appropriate for forward test year applications. Energy Probe agreed with this. PowerStream submitted that if there is a requirement to disclose material events then there should be the ability to adjust for other items, not currently contemplated, such as costs arising from labour contract costs.

Conclusions

The Board agrees that requiring disclosure of material events expected in 2006 is not warranted in those cases where the applicant has opted for a historical 2004 test year or an historical 2004 test year with adjustments. Under the historical 2004 test year options, there will be either no adjustments or only limited adjustments for specific, defined items. In these cases the Board sees no need for an examination of additional material events expected in 2006. For any future 2006 test year applications, comprehensive evidence and a thorough analysis will be required, and therefore full disclosure is warranted and will also be required.

Adjustments to the 2004 Historical Test Year

The Draft Handbook contains two sets of adjustments for an applicant choosing to file on the basis of an adjusted 2004 historical test year: Tier 1 adjustments and Tier 2 adjustments.

Tier 1 adjustments are intended to move the 2004 data closer to a "typical" year in terms of capital investments, operations and revenues and to allow for limited specified adjustments. If a distributor makes any Tier 1 adjustment then all Tier 1 adjustments must be made if the circumstances triggering them occur.

Tier 2 adjustments are optional and are intended to restore both capital investments not made and distribution expenses not incurred. An applicant would be eligible to make Tier 2 adjustments only if it began the 1999 RUD process with negative returns or if it did not receive the second installment of the market-adjusted revenue requirement increment. An applicant wishing to make any additional adjustments would be required to file on a full 2006 forward test year basis.

Consensus was not reached for the following adjustments:

- OEB annual assessment and other regulatory agency costs
- Non-routine/unusual adjustments
- New transformer stations
- Low voltage/wheeling adjustments
- Conservation and Demand Management (CDM) and Smart Meters

OEB annual assessment and other regulatory agency costs

There was no opposition to this adjustment, but CCC and Schools cautioned that the definition of "other regulatory costs" should be clear. Schools proposed that the adjustment be limited to "OEB annual fees and other fees paid to energy regulators".

Conclusions

The Board agrees that this adjustment should be closely circumscribed, and should be limited to the OEB annual assessment and other fees paid to energy regulators.

Non-routine/unusual adjustments

In the Draft Handbook, non-routine/unusual adjustments are defined as "readily-known, quantifiable, and verifiable occurrences, taking place in 2004 only, which exceed the materiality thresholds defined in the relevant sections of the 2006 Handbook."

Examples include a bad debt write-off, natural disaster, and mergers and associated costs.

No stakeholders opposed this type of adjustment. Toronto Hydro acknowledged that material non-recurring cost discrepancies should not form the basis of ongoing base rates. CCC submitted that such items should not be difficult to identify and report. Greater Sudbury expressed concern that its distribution costs would be understated unless it could adjust for the labour dispute that took place in 2004. Schools responded that just such an event would be captured by the non-routine/unusual adjustments if it were material.

Schools also submitted that the same information and level of detail should be required for items that are adjusted as for those items where the applicant believes no adjustment should be made.

The draft Handbook contained a note indicating that there might be an inconsistency between the treatment of non-routine/unusual bad debt as a Tier 1 adjustment and as a distribution expense adjustment. This section will address the Tier 1 adjustment issue. The distribution expense issue is dealt with in the discussion on chapter 6. All the stakeholders who commented on this issue agreed that if there were a write-off for a non-routine/unusual material bad debt in 2004, then an adjustment should be made to remove this for 2006 rate setting purposes. Routine or usual level of bad debt would not need to be removed.

The draft Handbook indicates that mergers and acquisitions taking place after 2004 are to be dealt with outside the 2006 rate-setting process. Both CCC and LPMA addressed the issue of 2004 mergers and acquisitions. CCC submitted that these costs should not be left in 2004 without the inclusion of expected efficiency benefits. LPMA suggested that those distributors with 2004 mergers or acquisitions should be considered for a forward test year.

There were submissions that additional distribution expense adjustments should be included. For example, Greater Sudbury and London Hydro submitted that costs associated with labour contracts should be included if the amounts are known with certainty for 2005 and 2006. Schools responded that adjustments for 2005 and 2006 would be unfair if no account were taken of productivity improvements or load growth.

Conclusions

The Board will require applicants filing on an adjusted historical test year basis to identify and adjust for non-routine/unusual events in 2004, subject to the relevant materiality thresholds. Adjustments should not be made for items below the materiality thresholds. The Board will require the same level of detail about the non-routine/unusual event, whether or not the applicant seeks to make an adjustment as a result of the event. This level of disclosure is required to allow the Board to determine whether or not an adjustment is appropriate. An applicant choosing not to make any Tier 1 or Tier 2 adjustments is not required to disclose any non-routine, unusual events, but interrogatories may be asked about unusual costs that may point to an unusual event.

With respect to bad debt, the Board agrees that a non-routine/unusual material bad debt write-off should be removed and that routine immaterial bad debt write-off need not be removed. With respect to mergers and acquisitions, the Board agrees that costs associated with this activity in 2004 should be considered for a non-routine adjustment, subject to the materiality threshold.

With the exception of the specifically permitted adjustments, additional expenditures expected in 2005 or 2006, even if they are known with certainty, will not be allowed under the adjusted historical 2004 test year approach. Inclusion of such adjustments would not be appropriate without a full assessment of all the related factors. It remains open to an applicant to apply on a forward test year basis, under which a full assessment can take place.

New transformer stations

The Draft Handbook includes new transformer stations (and directly associated assets) with an expected in-service date in 2005 within the Tier 1 adjustments. The Draft Handbook contains two alternatives for the treatment of transformer stations expected in 2006. Alternative 1 includes these assets, and Alternative 2 excludes them.

Distributors submitted that transformer stations with an in-service date in 2006 should be included, because:

- The costs will be known, as these additions are planned well in advance.
- If the costs are not included, it could cause financial problems for the distributor.
- These assets are primarily related to reliability and system optimization and the provision of additional capacity.
- Inclusion would mitigate future rate impacts.
- Toronto Hydro went further and submitted that any major capital expenditure should be included, without the need for a future test year application. Hydro Ottawa also submitted that adjustments should be available for major projects, such as its Geographic Information System.

Customer interests opposed the inclusion of 2006 transformer stations. In their view, if the capital costs are included, then the related increased revenues should also be included, and that, therefore, such adjustments are more appropriately part of a forward test year application. Hydro One took a similar view. LPMA submitted that only 2005 stations should be included and, even then, there should be a variance account or adjustment to reflect actual costs as soon as they are known.

Conclusions

The Board will include transformer stations expected to be in-service in 2005 among the Tier 1 rate base adjustments. The related adjustment to depreciation expense will also be required. The Board notes that there was no opposition to this adjustment. The Board will require that for this and all other 2005 Tier 1 and 2 rate base adjustments, the rate base and related depreciation impacts be assumed to occur mid-year. The Board will not require a variance account or application update to track the actual costs; the costs should be known with relative certainty and the Board expects the applicant to report the costs accurately.

The Board will not include transformer stations expected to be in service in 2006 among the Tier 1 adjustments. Adjustments related to 2006 are more appropriately made as part of a forward test year application. A forward test year application will ensure that there is a thorough examination of the forecast costs as well as a thorough assessment of related impacts, including increased revenue. The only exceptions to this are CDM expenditures, which are addressed in detail in Chapter 16, and Smart Meter expenditures.

Low voltage/wheeling adjustments

The Draft Handbook includes two alternatives for an adjustment for low voltage (LV) and wheeling costs.

Alternative 1 includes LV amounts approved for recovery by the Board in the Regulatory Assets Phase 2 decision, proposed LV amounts for the period January 2004 through May 2006, proposed Hydro One LV rates post May 2006 and wheeling charges where there are no established rates in place. Alternative 2 would only allow recovery where a Board decision has been made.

Customer groups generally supported Alternative 2, which requires a Board decision, although some, such as Schools and AMPCO, supported prompt decisions so the LV charges could be implemented. Schools noted that wheeling charges have not been discussed or debated before the Board.

Hydro One submitted that its application would include a proposal for new LV charges to take effect May 1, 2006. Because the Board will not be able to render a decision on this in time for the other 2006 rate applications, Hydro One proposed that embedded distributors could use the current approved LV rates applied to 2006 consumption levels for purposes of 2006 rates. Any resulting variance could be recorded in the RSVA Connection account. VECC responded that 2004 consumption should be used, not 2006.

Conclusions

The Board has previously approved Hydro One's LV charges, but these were not implemented in rates and instead flowed into a regulatory asset account. The Board has already determined that amounts in this regulatory asset account for the period ending December 31, 2003 will be recovered. This is set out in the Board's Phase 2 Regulatory Asset Decision. These amounts have been established for each embedded distributor.

The Hydro One LV amounts for the period January 2004 through May 2006 will be disposed of in due course, and the Board will shortly issue a filing guideline to this effect.

The Board does see merit in Hydro One's proposal for post-May 2006 LV rates. LV rates do need to be built into the rates of embedded distributors. Distributors will be allowed to adjust for the Hydro One LV charges based on the currently approved rate. The RSVA Connection account can be used to record the difference between the currently approved amount and the amount that is ultimately payable to Hydro One. The Board agrees with VECC that it would be inappropriate to use a 2006 consumption forecast for this item alone; 2004 data will be used.

With respect to LV charges of host distributors other than Hydro One, the Board will allow recovery of those charges by embedded distributors in cases where the host distributor has received Board approval for the rate before the 2006 rate application filing deadline.

Wheeling rates have not been subject to the same level of review as Hydro One LV rates. The Board will therefore only allow inclusion of these costs where a Board decision has been made.

CDM and Smart Meters

The Draft Handbook contains "placeholders" for CDM and Smart Meters.

Some stakeholders submitted that CDM and Smart Meters should be separated. AMPCO and SEC submitted that 3rd tranche amounts should not be included in distribution expense or rate base. Enbridge, Enersource Hydro Mississauga (Enersource), PowerStream and Toronto Hydro opposed this approach, and submitted that amounts related to 3rd tranche spending should be eligible for inclusion in rate base.

Conclusions

The Board agrees that CDM expenses and Smart Meters expenses should be reported separately. Distribution expenses related to 3rd tranche CDM expenditures are not eligible for recovery because they have already been recovered. However, 3rd tranche funds are eligible for inclusion in rate base, just as any other distribution related investment would be.

Chapter 16 of this Report deals with CDM adjustments in detail. In brief, spending proposed to be approved by the Board for 2006, incremental to the amounts in the 3rd tranche, should be included as a Tier 1 adjustment to operating expenses or to rate base, as appropriate.

Tier 2 Adjustments

The purpose of Tier 2 adjustments is to restore both capital investments not made and distribution expenses not incurred due to one or both of the following circumstances:

- The applicant began the 1999 RUD process with negative returns.
- The applicant did not receive the second third of the market-adjusted revenue requirement increment.

Tier 2 adjustments were proposed to be optional. The draft Handbook sets out that an applicant must do the following in support of its claimed Tier 2 adjustments:

- demonstrate that it has suffered hardship as a result of one or both of the circumstances outlined above
- demonstrate that the proposed incremental distribution expenses and capital spending levels are justified by the hardship it has experienced, including how the applicant determined that these amounts are attributable to the two circumstances outlined above
- provide details on the activities that will be undertaken if the proposed incremental spending is approved, including specific details as to the nature of the envisaged activities and their timing on a monthly basis

The draft Handbook sets out two alternatives as to the total amount that may be claimed. Under Alternative 1, the maximum level of adjustment would be the equivalent of one year's revenue shortfall (attributable to the two identified circumstances). Under Alternative 2, the maximum level of adjustment would be equivalent to the total revenue shortfall (attributable to the two identified circumstances) for all relevant prior years.

A number of distributors supported Alternative 2. In particular Brantford Power, Aurora Hydro and Scugog Hydro argued that distributors should be permitted to recover all forgone returns without being subject to the test of hardship or system deterioration. In their view, the negative returns were the result of external actions, for which they should not be penalized. However, if the Board were not to adopt this approach, then they would support Alternative 2, with a rate rider over a period that matched the corrective investments, ideally no more than 2 years.

Customer representatives were divided on this issue. AMPCO supported Alternative 1, because Alternative 2 would, in their view, lead to other attempts to retroactively correct past inequities. LPMA also supported Alternative 1 and indicated that variance accounts should be used to track actual expenditures.

Schools, CCC, and VECC supported Alternative 2. These parties supported the need to allow a distributor to take corrective action to ensure its system is sufficiently maintained. In their view, these adjustments are not about shareholder returns, but about ensuring a distributor has enough money to run the system properly and ensure it is at the appropriate standard. In their view, these requests would need to be thoroughly supported, and consideration should be given to spreading the costs over a longer period if there were significant rate impacts.

Conclusions

The Board agrees with the submissions of Schools, CCC and VECC. The issue here is not about adjusting shareholder returns; the issue is one of appropriate system maintenance. The Board is also of the view that these claims must be fully justified and supported. The Board will adopt Alternative 2, subject to the requirements regarding the demonstration of hardship, justification and plan for the expenditures. However, the Board will not require monthly projections and monitoring; quarterly projections and monitoring will be sufficient. The Board will establish a variance account for any applicant receiving a Tier 2 adjustment. If expenditures are lower than approved, the funds will be returned to ratepayers. However, if expenditures exceed the plan, the Board would not expect these amounts would be eligible for recovery.

As is the case for Tier 1 rate base adjustments, the Board will require that the rate base and related depreciation impacts be assumed to occur mid-year.

CHAPTER 4: RATE BASE

Chapter 4 of the Handbook deals with rate base issues, including the definition of the rate base, appropriate amortization rates, capital investments, interest on deferral accounts and Construction Work in Progress (CWIP), capitalization policy, contributed capital and treatment of capital gains and losses.

The capital investments sections deal with materiality thresholds for both IT-related and non-IT related capital expenditures, while the treatment of capital gains and losses section states that such gains and losses will be dealt with by the Board on a case-by-case basis, subject to materiality thresholds.

The section on Interest on Deferral Accounts and CWIP deals with appropriate interest rates on these items. The Handbook and the submissions of parties raised several issues to be considered in this chapter:

- definition of rate base
- calculation of rate base amounts
- amortization rates
- interest rate for deferral accounts
- interest rate for CWIP
- treatment of capital gains and losses

Definition of rate base

The question was raised as to whether there was a need for modifications to the definition of the rate base. One specific proposal in this regard related to transformer assets, which are now classified as non-distribution, but have been deemed as distribution assets in certain instances by the Board.

Conclusions

By definition, the rate base contains all of the assets used by the distributor in providing the regulated service, which is subject to the rates approved by the Board. In order to be considered as part of the infrastructure forming the rate base, assets are subject to prudence review. The Board must be satisfied that the asset sought to be included in the rate base is essential to the provision of the regulated service and has been procured or created at a price that is reasonable in the circumstances existing at the time of its creation or procurement. If the asset is unnecessary, over-sized, under-sized or too expensive, the claim for its inclusion in rate base will be denied to the extent its fails to meet a reasonable prudence standard. This consideration applies to transformation assets and other transmission-related assets that have been acquired or created by a distributor, as it does for other kinds of assets.

A distributors that has developed transmission-related assets must expect that before such assets can be included in rate base, they will be subject to a prudence review, and must have been deemed to be distribution assets pursuant to section 84 of the *Ontario Energy Board Act, 1998*. This caution is not intended to discourage the prudent development of such assets. Each case will be considered on its merits, in the light of prevailing circumstances. Accordingly, there is no need to provide for a separate category of rate base reserved for deemed distribution assets.

An applicant who seeks to have transmission related assets deemed to be distribution assets should make this request in the summary of the application.

Calculation of rate base amounts

The Board also considered the basis of the calculation of rate base amounts, specifically whether it should be net fixed assets at year end, or an average of the balances at the beginning and the end of 2004.

Conclusions

The diversity of views on this subject is represented in the submissions of Energy Cost Management Inc. (ECMI) and LPMA. The Board considers that the use of the average of the opening and closing balance for 2004 offers the most reliable figure without imposing an unreasonable burden on the distributor. Some parties suggested that using the 2004 year end number was preferable because it is temporally closer to 2006 and is, therefore, somewhat more relevant to the setting of rates for 2006. The Board does not accept this line of reasoning. We are not trying to forecast a rate base number. The object is to arrive at a data set that is more representative of a typical year in the life of the distributor.

Amortization rates

With respect to amortization rates, the Board has developed the rates reflected in Appendix B of the Handbook to provide a consistent and equitable approach to this aspect of financial management. While a distributor is permitted to deviate from those rates, it must provide rigorous support for the proposed deviation in the form of an amortization study.

Materiality thresholds

With respect to materiality thresholds for non-IT-related capital investments, the Board notes that three alternatives are presented. Alternative 1 proposes the use of the lower of either dollar value or percentage of fixed assets thresholds. These thresholds are identical to those proposed for IT-related capital investments about which there was no disagreement among parties. Alternative 2 proposes the use of Alternative 1's percentage of fixed assets threshold only. Alternative 3 is identical to Alternative 1, except it proposes higher thresholds for distributors with a rate base of under $100 million.

Conclusions

The Board concludes that the use of Alternative 1 will provide the most appropriate thresholds for non-IT-related capital investments. The Board is of the view that, as noted by Schools, the establishment of differing materiality thresholds for IT-related and non-IT-related capital expenditures will create unnecessary complexity and also, as noted by both Schools and LPMA, the adoption of Alternative 1 will provide materiality thresholds more in line with those of the gas utilities.

The Board is mindful of the concerns of some parties that the adoption of Alternative 1 may create excessively burdensome filing requirements for some distributors. The Board notes that the 2006 rate-setting exercise will be the first cost of service review undertaken by the Board for electricity distributors and, as such, the Board has no prior experience on which to base the establishment of these thresholds. Accordingly, the Board is of the view that it is most appropriate, at least initially, to require the filing of more information, rather than less. In the event these thresholds prove to be overly burdensome to applicants, stakeholders and the Board, they will be subject to review and revision prior to subsequent proceedings.

Interest rate for deferral accounts

The question of the appropriate rate to be used for deferral accounts attracted significant stakeholder comment. The Board agrees with the observation that the truly critical element of deferral management concerns the timely recovery or disposal of the principal amount captured in the deferral or variance account, not the interest rate attaching to it.

VECC's witness suggested an approach to deferral and variance accounts where all but the smallest distributors would attract interest rates below prime. Distributors generally argued for the use of the embedded cost of debt as the operative deferral and variance account interest rate. Others urged the Board to stipulate a short-term rate to be updated regularly. The purpose underlying the setting of a rate for deferral and variance accounts is to ensure that distributors neither gain nor lose inordinately in carrying the balances in these accounts.

Conclusions

It has been the Board's practice to refrain from establishing a one-size-fits-all interest rate for deferral and variance accounts. In considering this issue the Board seeks to find an approach that balances equity and ease of application. The Board has also been informed by the commentary during the oral portion of the consultation. In a number of instances witnesses commented that it was most appropriate to consider the specifics of the content of the deferral account when establishing the interest rate. A longer term rate is most appropriate when the account contains funds accumulated with an expectation of clearance over a number of years. In other cases, a short-term interest rate is most appropriate because the deferral or variance account is expected to be cleared within a year. Indeed, the legislation governing the Board's treatment of deferral accounts encourages clearance as soon as reasonably possible. A further consideration involves deferral and variance accounts that are relatively large. In such cases a distributor may find it difficult to secure financing of the account at short-term rates, even if clearance of the account is expected to be in the short term.

The Board concludes that its current practice is appropriate and will continue for the purposes of existing accounts. The Board will generally establish an interest rate to be applied in the case of a deferral account at the time the deferral account is established. In this way, the Board can tailor the interest rate to circumstances of the account and, where applicable, the specific distributor.

Parties are also reminded that it is the Board's intention to conduct a review respecting the issues involved in establishing the applicable cost of capital. While no specific timetable for this review has been established, a distributor may find it cost effective to await the review rather than engage in trying to establish novel approaches in their 2006 rate applications.

Interest rate for construction work in progress

The related question of what interest rate should be used for construction work in progress (CWIP) was less controversial.

The Board's current practice is to not provide any particular guidance with respect to the interest rate to be applied to funds used in construction projects. In the course of the oral portion of the consultation, VECC presented the expert evidence of Mr. G. Matwichuk, who supported the use of a methodology for the imposition of an interest rate in these circumstances. In essence, Mr. Matwichuk's proposition involves the use of the Weighted Average Cost of Capital for distributors with an appropriate debt/equity ratio, or, in the case of distributors financed primarily by debt, the use of the prevailing Interest During Construction (IDC) rate. Overall his methodology can be identified as an Allowance for Funds Used During Construction (AFUDC).

Conclusions

The proposed methodology has the advantage of providing some definitive direction to distributors with respect to an appropriate rate, and introduces enhanced consistency over the distribution industry in the Province. The use of the WACC is appropriate given the capital nature of the assets produced through such projects. It reflects the predictable cost of capital experienced by the distributor, should it have to, or want to, finance the project in the market. The same reasoning applies to the use of the IDC for a debt-financed distributor. Should it need to raise money to finance the project, it would be at a cost equal to the interest rate prevailing during the construction period.

The Board considers the methodology proposed by Mr. Matwichuk to be appropriate, and will adopt it for use in the Handbook.

Treatment of capital gains and losses

The Board received submissions on the regulatory treatment of capital gains and losses. This subject matter attracted strong views on both sides. Some parties argued for the entitlement of ratepayers to some or all of the proceeds of sales of assets. In their view, ratepayers have created the assets used by the distributor through the payment of rates, and therefore should have a share in sale proceeds. On the other hand, distributors argued that ratepayers have an entitlement to just and reasonable rates, but not to any divisible share in the assets used by the distributor. This discussion assumes that the sale price is equal to or greater than the fair market value of the asset.

Conclusions

In the Board's view, there is a preliminary issue. A Board consideration of the distribution of proceeds of sale should only be undertaken when the proceeds exceed a threshold amount. Elsewhere in this Report, the Board has adopted a materiality threshold with respect to distributor assets for a variety of purposes. The Board concludes that the thresholds found in section 4.2 of the Handbook should apply to the consideration of the distribution of the gain or loss arising from sales of assets. For assets sold to a non- affiliate, where the fair market value of the gain or loss falls below the materiality threshold in the chart, the gain or loss shall be shared between the ratepayers and the shareholders on a 50 / 50 basis. For assets sold to an affiliate, the threshold applies to the value of the asset, not to the value of the gain or loss. The same 50 / 50 split between ratepayers and shareholders applies to assets falling below the threshold.

In the Board's view, all other cases should be determined case-by-case. The Board will generally expect that any capital gains or losses on the transfer of utility assets should be shared 50 / 50 between ratepayers and utility shareholders. However, each rate panel will need to determine if there are circumstances that justify a different treatment.

CHAPTER 5: COST OF CAPITAL

Chapter 5 describes the determination of the various components of cost of capital. The following issues are addressed in this report:

- Maximum allowed return on equity
- Debt rate
- Working capital allowance

Maximum allowed return on equity

During Issues Day, the Board approved the use of a mechanistic update consistent with the methodology used by Dr. Cannon in his 1998 paper "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities" to set both maximum allowed return on equity and debt rates for 2006 rate applications. The Draft Handbook contains an example based on July 2004 data from the Bank of Canada and from Consensus Forecasts. It was not intended that this update in and of itself would be used for setting 2006 distribution rates. The return on equity and debt rates used for 2006 distribution rate setting were expected to be calculated based on data that would be closer in time to the actual 2006 rate year.

The Draft Handbook contained two options with this in mind:

- Alternative 1: The Board will determine the maximum allowed return on equity for 2006 using the most current data available at the time it releases its 2006 EDR decision; or
- Alternative 2: If there are changes to the Bank of Canada's 10- and 30-year Bond rates, the Board will issue a new return on equity annually. The Board will use the December forecast prior to the rate year to establish the maximum allowed return on equity. Given the complexity of changing the rate schedules for all distributors prior to implementing rates in May 2006, distributors will track the difference between the 2006 Handbook-issued rate, and the Board's updated maximum allowed return on equity, in a variance account.

The following parties supported Alternative 1: AMPCO, Canadian Manufacturers and Exporters (CME), CCC, ECMI, LPMA, School Energy Coalition, Enbridge and Toronto Hydro. Parties supporting Alternative 2 were the following: the Electricity Distributors Association (EDA), Hydro One, and Hydro Ottawa. The preference between the two Alternatives was not clear-cut. ECMI, in its responding evidence, also commented that Alternative 2 could provide some certainty to distributors, financial institutions and to customers "in the event that interest rates shift". Hydro Ottawa, while supporting Alternative 2, commented that Alternative 1 was also acceptable given the "accelerated timeframe for the 2006 rates".

Energy Probe recommended a two-stage alternative. In the first stage, the Board would calculate and publish in early June 2005 updated Cost of Capital parameters based on May/June 2005 Bank of Canada and Consensus Forecast data, and distributors would make their 2006 rate applications based on these published numbers. Later, the Board would set an updated rate based on current data, at which point distributors would apply for final rates taking into account the updated Long Canada Bond Rate (and its impact of return on equity and debt rates).

Conclusions

Many of the parties supporting Alternative 1 noted its simplicity compared to that of tracking the variance for later reconciliation. Several parties also commented on the certainty that the updated but preset ROE and debt rates would provide to distributors, their shareholders, the financial community and customers. The Board concludes that the simplicity and certainty provided by Alternative 1 are attractive attributes.

While the Board considers that all aspects of the rate-setting methodology and applications should be based on the best information available, it must balance the practicality against the incremental improvement gained. The two-phase process proposed by Energy Probe has precedents in the Board's regulation of natural gas utilities, but in this case the Board believes that this approach would extend the time and effort needed for the processing of the applications. In the Board's view, the complexities introduced by Alternative 2 imply a precision in the cost of capital parameters that are unwarranted and unnecessary.

While it notes the comments of parties, mostly distributors, of the extended time between when the update is calculated and when the 2006 rates will be effective, the Board does not consider that this creates undue financial exposure to distributors and their shareholders. The first few years of this new millennium have seen a prolonged period of consistently lower inflation and interest rates.

The Board adopts Alternative 1 and will calculate the updated maximum allowed return on equity and deemed debt rates using the most currently available Bank of Canada and Consensus Forecast data. The calculated cost of capital parameters will be documented in the 2006 Handbook and used in the model.

Debt rate

The methodology underlying the unbundling of electricity distribution rates in 2001, and which is factored into current distribution rates, uses the Board-approved deemed debt rate. The Board-approved deemed debt rate varies with the rate base size of the distributor. This approach was adopted in light of the fact that the overwhelming number of electricity distributors in Ontario at that time had little history operating as commercial corporations.

Distributors have now been operating as commercial corporations for several years, and have obtained debt financing with both affiliated and non-affiliated entities. Some stakeholders suggested that the continued use of a deemed debt cost, whether updated or not, was not appropriate. The draft Handbook included a proposed method of using the embedded cost of debt, or a proxy for it. This approach is more consistent with the Board's practice in rate setting for natural gas utilities.

One concern that arises with this proposed methodology concerns the danger that a distributor may place debt with affiliated entities at interest rates that are higher than those prevailing in the market. To preclude any opportunity for a distributor to obtain debt from an affiliated firm at higher than a market-based rate, the deemed debt rate would be used as an upper boundary for debt placed with an affiliated entity; if the actual debt rate for the debt instrument is lower than the deemed debt rate, the actual rate should be used.

Conclusions

There were two proposals in the draft Handbook, which differed only as to which deemed debt rate should be used as the upper boundary for the debt rate where the debt holder is affiliated to the distributor. The Board agrees with the majority of parties commenting on this matter that where the debt is held by an affiliated firm, the lower of the actual rate and the size-related deemed debt rate that was in effect at the time that the debt was issued will be used. For debt held by an unaffiliated firm, such as a chartered bank, the actual debt cost (rate) will be used. This methodology is documented in Schedule 5-1 of the Handbook and will be integrated into the model.

Working capital allowance

The Working Capital Allowance (WCA) forms part of the rate base and represents the estimated cash required by a distributor to support operations in advance of recovery in rates. WCA for electricity distributors is presently calculated as 15% of the sum of the cost of power and certain distribution expenses.

The Draft Handbook presented four methodologies for the calculation of the WCA. None of the four alternatives proposed a change to the 15% figure, or in the designation of the distribution expenses used in the calculation. The issue addressed by the various alternatives was the estimation of the cost of power component of the calculation, and whether this cost should be estimated, updated, or trued up at the end of the year. Alternative 2 in the Draft Handbook would use the historical cost of power data, but would "update" that cost by way of a forecast of anticipated rate increases for 2006. The forecast would be prepared by the Independent Electricity System Operator. The 15% calculation would then be applied to the adjusted, forecast cost of power estimate.

Alternative 3 would use a variance account instead of a forecast to bring the cost of power up to date at year's end. Alternative 4 is analogous to Alternative 1, but represents a substantial refinement of it, and provides more specific guidance to distributors in preparing the WCA claim.

Conclusions

At its best, the WCA is a fairly blunt instrument, designed to provide an adequate ongoing cash flow to distributors in advance of recovery through rate collection. Its most meaningful component is the cost of power, and cost items associated with the cost of power, which represent the distributor's primary business liability.

The Board must weigh administrative simplicity against precision. The use of a forecast reflecting forecast increases in the cost of power, or the use of a variance account to capture the same introduce a level of complexity which is unnecessary. First, it is unclear that any such forecast will be available at the relevant time, which is mid-2005, or that the forecast will have inherent reliability. Prediction of rate levels is a very uncertain undertaking. It is not clear that essential inputs to underpin such a forecast would be available in time to inform the 2006 rate process. While deferral and variance accounts are useful tools in this regulatory environment, they should only be used when genuinely necessary. Establishment of the WCA is not such a case.

As between Alternative 1 and 4, the Board favours an evolution to the somewhat more prescriptive Alternative 4. It has the virtue of being a more precise tool, while not introducing new elements of judgement or uncertainty. The inputs for the calculation of the account are discrete and flow directly from relevant factors readily applied. Once again, the Board cautions all distributors that more refined data management and reporting requirements will be a feature of the regulatory environment going forward. The Board will therefore adopt Alternative 4 as the model for the calculation of the WCA.

A question remains as to the role that customer deposits should play in the determination of the WCA. Ratepayer groups generally favour reducing the amount of the WCA by an amount equal to security deposits held by the distributor. They argue that the deposits represent a fund of cash on hand that should be brought to bear as working capital. They suggest that the deposits are procured to cover the cost of the commodity supplied to a customer when the customer becomes unable to cover its overall distribution account. The cost of the commodity is the key component to the WCA calculation. On the other hand, the distributors suggest that the security deposits represent a discrete account, designed to fund delinquency for individual ratepayers, and are subject to return to ratepayers under the terms of the Distribution System Code. They also note that interest accrues to the ratepayer while the deposit is in reserve.

Conclusions

Security deposits are not currently set off against the WCA for electricity distributors. The Board regards the security deposits to be in the nature of funds in trust, pending use to reduce delinquency, or return to the customer. Their inclusion in the WCA is inconsistent with this character, and the Board will not require the WCA to be reduced by the amount of security deposits held.

CHAPTER 6: DISTRIBUTION EXPENSES

Chapter 6 of the 2006 Handbook explains how a distributor should organize and support the distribution expenses component of its 2006 revenue requirement applications. The Draft Handbook proposes that a distributor be required to file three years (2002, 2003 and 2004) of distribution expense data. For certain specific items, such as affiliate transactions, additional filling requirements are proposed.

This report addresses the following issues:

- self-insurance expense
- bad debt expense
- advertising expense
- charitable contributions
- supporting evidence for meals / travel and business expenses
- compensation disclosure rules for two, or fewer, employees
- additional salary disclosure rules where employees make greater than $100,000
- incentive plans
- distribution expenses paid to affiliates

Self-insurance expense

The Draft Handbook contains two alternatives related to self-insurance. Alternative 1 allows for inclusion of a reasonable amount of the self-insurance reserves. Alternative 2 allows for the inclusion of the actual expenses for self-insurance claims, but not changes in the reserves.

Views were mixed on this issue. EDA, Hydro One, Hydro Ottawa, CME and Schools favoured Alternative 2, primarily because it is simpler and does not require forecasting. Toronto Hydro favoured Alternative 1. VECC also favoured Alternative 1, provided a concrete policy existed, but suggested in reply argument that under Alternative 2, a three year average could be used.

Conclusions

Actual self-insurance claims in any particular year, in this case 2004, are not necessarily representative of claims on average. However, forecasting the reserve requirement, which smoothes losses, is subject to judgement and therefore may be more difficult to assess from a regulatory perspective within the abbreviated approach to 2006. The Board sees merit in VECC's proposed modification regarding recoverability of self-insurance expenses and will adopt Alternative 2, adjusted to use the average of actual claims in the period 2002-2004.

Bad debt expense

Board staff has noted what appears to be an inconsistency between Chapter 3, which prescribes removal of an unusual material bad debt write-off as part of a Tier 1 adjustment and Chapter 6, which provides for the potential recovery of a 2004 bad debt in 2006 rates.

The Board has already determined that a write-off for unusual 2004 bad debt is an appropriate Tier 1 adjustment in order that 2004 data is adjusted to reflect a more "typical" year. What remains to be determined is whether a unusually large bad debt write-off in 2004 should nevertheless be eligible for recovery.

CCC submitted that material bad debt should not be a recoverable expense, and that if a distributor were allowed to recover a bad debt, then the return on equity should be reduced to reflect a lower level of business risk. Similarly LPMA and Schools submitted that there should be no recovery of an unusual bad debt.

ECMI and Barrie Hydro submitted that bad debt should be treated as Tier 1 adjustment and as a Z-factor rate rider. PowerStream suggested that all 2004 bad debts should be recoverable, pending an updated risk assessment in 2007. In contrast, Toronto Hydro generally agreed that an unusual cost should be excluded from the test year.

Energy Probe proposed that there should be an allowance for bad debt in rates, but that the 1999 allowance should only be adjusted if a comparison between the allowance and actual bad debt loss (net of major customer failure) is available. VECC submitted that the allowance for bad debt should be based on a "typical" amount, or a three-year average.

Conclusions

The Board has already concluded that a non-routine bad debt write-off should be removed from 2004 expenses for purposes of setting the 2006 revenue requirement. What is at issue is whether that non-routine bad debt should still be recovered through rates through some other mechanism, such as a rate rider. The Board agrees with CCC that to allow recovery of these types of losses would require a re-assessment of the distributor's risk level. Risk is not being addressed in this proceeding. To the extent that bad debt expense of a routine nature is included in 2004 data, then that amount will remain for purposes of determining 2006 rates. However, individual, material bad debt write offs in 2004 must be separately identified and will not be recoverable in 2006 rates.

Advertising expense

Board staff suggested that the wording in this section be revised to say, "Advertising expenses incurred for the primary purpose of promoting corporate branding or image are not to be included in determining the applicant's 2006 revenue requirement." Only VECC commented on this suggestion, and it supported the change.

Conclusions

The Board will incorporate the change into the Handbook.

Charitable contributions

With respect to charitable contributions made by a distributor, three alternatives for recovery in 2006 rates were proposed. Alternative 1 would allow for 50% recovery of regular contributions and 100% recovery of programs that assist in payment of electricity bills. Alternative 2 would allow no recovery, and Alternative 3 would allow full recovery.

Some distributors supported Alternative 3. For example, Hydro One believed full recovery would be appropriate, provided the donations benefited the community served. Hydro Ottawa noted that distributors made contributions in 2004 and it would be unfair to change the rules now. Schools, VECC, and PowerStream submitted that donations should be recoverable but limited to a common prescribed maximum level.

ECMI supported Alternative 1 and further suggested that, even if this is denied, the 100% recoverability of donations to charities assisting with consumption should be retained. Similarly, Hydro Ottawa argued that if the Board adopts Alterative 1, then this should be expanded to include 100% of safety and CDM related donations. VECC, in its reply submissions, supported recovery for programs that assist customers in paying their bills.

AMPCO and CME supported Alternative 2, as did CCC, noting that this option is consistent with natural gas sector rules. LPMA submitted that these should be corporate or shareholder expenses, not ratepayer expenses.

Conclusions

The Board concludes that charitable donations will not be allowed for the purposes of 2006 rates, except for contributions to programs that provide assistance to the distributor's customers in paying their electricity consumption bills.

The Board understands that charitable donations may well benefit the communities served by the distributor. However, these expenses are not related to the provision of electricity distribution services and therefore do not appropriately form part of the revenue requirement. The Board is seeking ways to address the issues raised in relation to low income consumers and will therefore allow recovery of donations related to assisting customers with their electricity bills. These expenditures are more directly related to the provision of electricity distribution services.

The Board is not convinced that expanding the scope for recoverable charitable donations for safety and CDM related expenditures is warranted. If a distributor makes CDM related charitable donations, then that should be considered within the context of the overall CDM budget and plan. CDM issues are addressed in more detailed in Chapter 16. Similarly, the distributor has a range of safety obligations, and those expenses are recoverable to the extent they are related to the distribution business. The Board does not believe it is necessary to make provision in rates for additional expenditures related to donations in these areas.

Contrary to Hydro Ottawa's view, excluding charitable donations does not constitute an unfair change in the "rules". A distributor may well have made donations in 2004, but those expenses themselves are not now being disallowed. What is disallowed is a provision for a "typical" year, and therefore 2006 rates. The Board notes that the distributor can control whether donations are in fact made in 2006.

Supporting evidence for meals/travel and business expenses

The issue is whether or not distributors should be required to file a copy of their written policy or policies for meal, travel, and business entertainment expenses.

Customer groups supported mandatory filing of the policy/policies. LPMA submitted that if a distributor does not have a written policy in this area, then it should develop one. VECC supported mandatory filing on the basis that it would reduce interrogatories.

Distributors submitted that it should not be mandatory to file the policy or policies, although Hydro One and Hydro Ottawa suggested that an applicant could provide a summary of policies in the application. EDA submitted that mandatory filing would be seen as micromanaging.

Conclusions

The Board will require any existing written policies to be filed. This will not be burdensome to distributors, and will allow for a more expeditious review.

Compensation disclosure rules with two, or fewer, employees

The Draft Handbook contains two alternatives for applicants with two, or fewer, employees. Under Alternative 1, no employee compensation reporting is required if the average total compensation per employee is less than $100,000. Alternative 2 is that regular disclosure is required.

Most stakeholders supported Alternative 1, primarily due to privacy concerns. VECC suggested that the Alternative should apply for applicants with fewer than 3 employees, not fewer than 3 full time equivalents. Power Workers Union (PWU) submitted that no salary disclosure should be required for any applicant with fewer than three employees (regardless of salary level).

Conclusions

The Board concludes reporting of employee compensation for those applicants with fewer than 3 employees will not be required, regardless of the average total compensation. This will alleviate any privacy concerns.

Additional salary disclosure rules where employees make greater than $100,000

The issue is whether or not compensation for each employee making more than $100,000 per annum should be reported separately.

Customer groups supported disclosure, with limitations. CCC suggested that it might be more applicable to distributors with more than 50 employees. LPMA suggested that the applicant should provide the job title, but not the employee's name. VECC supported no disclosure so as to eliminate legal concerns. Schools submitted that distributors should be held to the same level of transparency as other public sector employees and

submitted that privacy legislation would not prohibit disclosure if a distributor were ordered to do so by the Board.
Distributors opposed mandatory disclosure. PWU questioned the need for individual compensation information to establish the prudence of compensation levels.

Conclusions
The Board will not require the separate disclosure of total compensation for each employee earning more than $100,000 per annum. The Board does not believe that this information is necessary to determine the appropriateness of the aggregate compensation.

Incentive plans

The Draft Handbook contains two alternatives with respect to compensation plans that reward employees for meeting specific performance targets. Under Alternative 1, costs associated with plans that are of substantial benefit to ratepayers may be included in the revenue requirement. Under Alternative 2, payments for incentives that primarily benefit shareholders will not be included in the revenue requirement.

Distributors favoured Alternative 1 or went further and submitted that there should be general recovery of incentive plan compensation. PowerStream submitted that plans benefit both shareholders and consumers through incremental returns and increased quality of service and lower costs going forward. Toronto Hydro questioned the practical basis for distinguishing between shareholder and ratepayer benefits and noted that earnings are a prime source of funds for re-investment.

Customer groups favoured Alternative 2. London Hydro and Schools requested that the Board clarify what specific types of incentive measures are considered to benefit ratepayers. LPMA argued that no costs of incentive plans should be in the 2006 revenue requirement, as any ratepayer benefits would not be reflected in the full 2004 costs; excluding the incentive payments provides a proxy of the benefits to customers.

Conclusions

Incentive payments that relate to benefits to shareholders will not be recoverable in the 2006 revenue requirement. If benefits flow directly to shareholders, then ratepayers should not be responsible for the related costs. The applicant will be required to file details of the incentive compensation plan, including a listing of the performance measurement criteria, and will be required to identify the shareholder related component and ratepayer related component.

The applicant will be responsible for justifying its claim that a performance measurement is ratepayer related. For general guidance, the Board would normally characterize targets related to rate of return, earnings and/or share performance as being shareholder-related. While earnings might flow back into the distributor in the form of additional investment, earnings flow to the shareholder, which retains discretion as to how those funds are used. Targets related to safety, environment, reliability, service quality, CDM and cost reduction could be considered customer related.

Distribution expenses paid to affiliates

The Draft Handbook identifies the minimum filing requirements related to distribution expenses incurred through affiliate transactions. Two areas included alternatives: proposed additional filing requirements and additional information regarding compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters (ARC).

Additional Filing Requirements

The Draft Handbook identifies a number of specific filing requirements related to expenses paid to affiliates, to which all of the stakeholders agreed. At issue is whether the applicant will also be required to file:

- Actual costs of the affiliate, where cost-based pricing was used for services or goods provided by the affiliate to the applicant, and
- Description of if and how the absence of a market was established before using cost-based pricing.

Customer groups supported the additional filing requirements. Some noted that the Board has already addressed this issue in relation to gas utilities. It was also noted that disclosure would reduce the requirement for interrogatories. VECC supported the filing requirement for material transactions. LPMA also submitted that the applicant should be required to file a description of the "specific" methodology used in determining prices, not the "general" methodology.

Schools submitted that any applicant with significant outsourced operations should be required to report external full-time equivalents (FTEs) and proposed the following wording:

> Any applicant that spends more than 10% of their distribution expenses on payments to affiliates and/or shared services shall prepare a schedule of equivalent FTEs, listing for each major functional area of the distributor's activities the FTEs employed to deliver that function, broken out into FTEs who are employees of the distributor, and FTEs who are provided through affiliates or shared services arrangements.

Distributors opposed mandatory disclosure. EDA submitted that it should be assumed that a distributor is in compliance and inquiries as to compliance should be left to the Board's compliance office. PowerStream submitted that additional filling requirements are unnecessary to determine compliance and noted that follow-up questions could be asked, if necessary. Veridian submitted that more detailed filling should only be required for distributors with outlier cost structures.

Conclusions

The Board will not require the filing of the additional information. When assessing any expenditure, the issue for the Board is whether the proposed cost is reasonable and should be recovered in rates. This issue arises whether the cost is related to an affiliate or a non-affiliate. In determining whether a cost is reasonable, one consideration is how the applicant determined what the item or service should cost. The applicant may provide evidence on this question, for example related to tendering, testing the market or reviewing the service provider's costs. If a rates panel hears evidence about how an applicant determined what the cost of an item or service should be, the panel will then decide whether the applicant has provided enough evidence to demonstrate the cost is reasonable.

The ARC does contain rules for establishing what the costs should be of affiliate services. These same criteria are relevant to the Board's determination of the reasonableness of the expense. The 2006 rates panel will determine the reasonableness of the costs, not compliance with the ARC. If the service provider is an affiliate, and it appears to the rates panel that there may be some question as to ARC compliance, the rates panel can indicate that they will pass the information on to the Board's Chief Compliance Officer. The rates panel will not make determinations regarding ARC compliance, nor explore how closely the applicant followed the provisions of the ARC.

The Board will adopt the revision proposed by LPMA regarding the price determination methodology. This change will indicate the need for precise information on the determination of prices, and not just vague descriptions.

Distributors with significant outsourcing, so-called "virtual utilities", pose a particular challenge in terms of a cost-of-service review for ratemaking purposes. The Board will require more extensive comparative data from any distributor that outsources more than 50% of its distribution business. Such distributors will be required to file, for all distribution services contracts where the value of the contract exceeds 0.2% of distribution expenses, the value of the contract, the amount capitalized, and an indication of into which accounts the costs of the contract are posted. If a tendering process was used for the contract, this should be stated.

Additional Information Regarding Compliance with the Affiliate Relationships Code

The issue is whether the following should be included in the Handbook:

> To help justify the reasonableness of amounts paid to affiliates for purposes of 2006 distribution rates, an applicant must provide a general explanation in

> Schedule 6-3 on how it followed the transfer pricing and shared service rules in the Affiliate Relationships Code.
>
> Where an applicant failed to follow a material requirement in the Affiliate Relationships Code transfer pricing and shared services rules, it will face additional scrutiny of these expenses in its 2006 distribution rate application. In such cases, the Board will specifically review the reasonableness of allowing full recovery of the amounts paid in the given circumstances.

Customer groups supported the inclusion of the requirement, and Distributors opposed it. Again, reference was made to the experience with the gas utilities. Union suggested that only compliance with ARC transfer pricing rules is relevant for rates, and not other ARC compliance matters. Hydro Ottawa submitted that the 2006 EDR process is not the appropriate vehicle to determine compliance with the ARC. PWU submitted that a review of ARC compliance would result in unreasonable delays and is more appropriately undertaken by the Board's compliance function. VECC argued that in order determine if the rates are just and reasonable the Board must determine whether the transactions are being priced in a manner consistent with the ARC.

Conclusions

The Board enforces its various codes, rules and orders through its Compliance Process. The Compliance Process includes provisions for investigation, negotiation and potential enforcement action. At issue is how distributors should report on ARC compliance, and where that should be tested. The Board concludes that the reporting and review of ARC compliance should not be conducted through the 2006 rate application process. The 2006 rate application process will be limited to a review of the expenses incurred through affiliate transactions and a determination of whether those are reasonable, as discussed above. The proposed wording will not be included in the Handbook.

CHAPTER 7: TAXES AND PILS

Chapter 7 of the 2006 Handbook explains how a distributor should calculate the amount of corporate income and capital tax expense to be included in its 2006 rates application. The Board will issue a 2006 regulatory tax calculation model that reflects the Board's conclusions, and distributors will use this model in their applications.

The following issues are addressed in this report:

- general principles
- true-up
- tax savings arising from non-recoverable or disallowed expenses, including purchased goodwill and charitable donations
- fair market value "bump"
- loss carry-forwards
- interest deduction
- sharing of tax exemptions
- undepreciated capital cost (UCC) and capital cost allowance (CCA)
- regulatory assets and liabilities
- CDM
- Smart Meters
- tax information disclosure

General principles

Stakeholders raised a number of issues in the area of general principles, many of which go to the objectives of setting the tax provision in rates. Where the term 'PILs' is used, the comments also apply to corporate taxes where the distributor pays taxes to the federal government.

The Draft Handbook indicates that the explanatory detail in the chapter may be removed in the final version of the chapter. However, Schools suggested that some background explanation should remain, so that readers can better understand the changes from past practice and hence improve compliance. LPMA also proposed additional wording related to the "stand-alone" principle, under which ratepayers only bear the costs, risks and benefits arising from the provision of regulated services.

In the section on regulatory taxes payable method, the Draft Handbook contains the following: "The tax amount included in rates is based upon taxes expected to be actually payable as a result of operating the distribution-only business, rather than upon taxes calculated for accounting purposes." The Coalition of Issue Three Distributors (CITD) submitted that the references to "taxes payable expected to be incurred" and "taxes expected to be actually payable" should mean the amount the Board calculates for ratemaking purposes, not the amount the distributor will calculate on its tax return.

LPMA submitted that the wording in the section on prudent management of taxes should be revised to state that a distributors is "required and expected" (rather than "allowed and expected") to manage taxes prudently.

Conclusions

Taxes are an important component of the overall revenue requirement. The Board has four guiding principles when determining the allowance for taxes in 2006 rates:

- The tax rates and tax rules used in the tax model should reflect to the extent possible the actual rates and rules that will be applicable in 2006.
- The inputs to the calculation should be consistent with the other components of 2006 rates.
- Rates must be just and reasonable, and any substantial variation between taxes determined for regulatory purposes and actual taxes paid by the distributor must be justifiable.
- The tax model should be reasonably simple.

Practically speaking, the third and fourth principles balance the first and second principles. The second principle incorporates the concept of the "distribution-only" business, or "stand-alone" distributor, but that cannot be the Board's only consideration.

The Board notes the concerns expressed by stakeholders regarding the potential difference between the level of actual taxes paid and the level allowed in rates. The Board intends to continue to monitor actual taxes paid and taxes recovered through rates to determine whether modifications to the Board tax methodology, or its application in the Board tax model, are required for future years. This will include an analysis of the differences between these two amounts, and a determination of the reason(s) for any material difference.

The Report will now address the specific initial issues raised. The conclusions reflect the application of the general principles outlined above.

The Board will retain sufficient explanation in the Handbook so that distributors and other stakeholders can understand the Board's objectives in this area and to assist a distributor in making accurate filings. A lengthy section on the "stand-alone" principle will not be included. The Board has addressed the stand-alone concept throughout this chapter of the Report, and the issue is dealt with directly in the section on tax savings arising from disallowed expenses. The Board believes this is sufficient to aid the understanding of stakeholders at this time.

With respect to the prudent management of taxes, the Board expects a distributor to manage taxes prudently and will set rates accordingly, but the Board is not explicitly "allowing" or "requiring" it to do so. The Handbook will be adjusted accordingly.

The draft Handbook includes a section on "PILS tax administration and tax rulings", which states that "the applicant's initial 2006 tax payable filing must account for the tax effect of the ruling or policy", if that policy or ruling is inconsistent with the 2006 OEB Tax Model. The Board has determined that this will not be required as part of the application; rather, for purposes of the application, an applicant will only be required to disclose the new policy or ruling.

True-up

The Draft Handbook contains two alternatives for the determination and recovery of the variance between taxes paid and taxes included in rates, otherwise known as the "true-up". Alternative 1 provides a partial true-up for tax driven factors, and Alternative 2 provides a full true-up for tax driven and operations driven factors:

- Alternative 1: Each distributor shall establish a 2006 PILs/taxes variance account to capture the tax impact of the following differences:
    - any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model
    - any difference that results from a change in, or a disclosure of, a new assessing or administrative policy of the Federal or Provincial tax authorities, if the Board has declared that such new or modified assessing or administrative policy is a change of general application that should be treated as if it were a change in tax rules
    - any difference in 2006 PILs that results from a tax re-assessment which is received by the distributor after its 2006 rate application is filed, and before May 1, 2007, and which relates to any tax year ending prior to May 1, 2006
- Alternative 2: A variance account will be set up for 2006 PILs/taxes. Any variance between actual taxes and forecast taxes should be credited or debited to this account, and should be cleared to ratepayers in the following year.

Toronto Hydro sponsored evidence by Mr. Krukowski and Mr. Erling of KPMG. Their conclusion was that the partial true-up is the most appropriate option because it results in less administrative burden, greater rate stability, and lower risk to distributors. They testified that with full true-up, the rate changes would magnify the earnings volatility arising from variations in revenue or expenses, and inappropriately pass the tax consequences to ratepayers.

Most distributors supported Alternative 1, in line with the KPMG recommendations. Schools, CME, LPMA, and VECC also supported the partial true-up.

Amongst distributors, only London Hydro and Niagara Erie Public Power Alliance (NEPPA) supported the full true-up. Enbridge and Union did not support any true-up.

There was also some discussion regarding the scope of the proposed true-up for prior year tax re-assessments and whether the wording in Alternative 1 accurately captured the intended effect. Stakeholders generally agreed that the intention was that the true-up of 2006 taxes relating to re-assessments of prior taxation years would deal only with the impact on 2006 taxes of those re-assessments.

In addition to changes in tax rates, rules and re-assessments, which are unambiguous, the partial true-up approach is also proposed to include "new or modified assessing or administrative policy" if the Board declares that the policy change is of general application and should be treated as a change in tax rules.

To paraphrase Schools, the issues with respect to this policy change provision are:

- How will the Board know that a change in policy has occurred?
- How will the Board determine whether such a change should be treated as being equivalent to a change in tax rules?

Schools submitted that changes are either communicated publicly through bulletins, circulars, and public rules or through individual audits or private rulings. In Schools' view, the Board should receive any public information directly and distributors should be directed to inform the Board of any changes which come to their attention, for example through an audit. Schools submitted that any changes that are published would be of general application and that the Board could assess any changes that arose through an audit. Schools acknowledged that this latter assessment could be complex.

Conclusions

The Board will adopt the partial true-up approach. The Board agrees that it would be inappropriate to adjust rates to account for tax differences arising from variations in revenues or expenses. The Board also accepts that a partial true-up for changes in tax rates, rules, etc. represents a reasonable balance of risk between shareholders and ratepayers for items which are beyond the control of the distributor.

The Board will revise the wording in the Handbook related to the true-up for prior year tax re-assessments so that the description of what is in the variance account addresses the issue of opening balances directly and is consistent with the intention as expressed in the "Tax re-assessments" section.

With respect to changes in policy, the Board will narrow this adjustment provision, in order to reduce the amount of discretion required and the amount of regulatory process needed. The Handbook will be revised to include only those changes in tax policy that are published in the public tax administration bulletins or interpretations by relevant federal or provincial tax authorities. The approach proposed by Schools, which includes policy changes arising from individual audits, introduces a level of complexity and additional regulatory burden that is not warranted in the circumstances

Tax savings arising from non-recoverable or disallowed expenses, including purchased goodwill and charitable donations

There are a number of situations where the distributor may be entitled to tax deductions for expenses or other items that are not allowed for regulatory purposes. The Draft Handbook identifies a number of these situations:

- Non-recoverable or disallowed expenses
- The impact on Eligible Capital Expenses (or Cumulative Eligible Capital) related to disallowed expenses (Purchased Goodwill)
- Charitable donations

The treatment of the resulting tax savings in each of these situations is in dispute. The Draft Handbook sets out three alternatives in each case:

- The tax savings are shared between ratepayers and shareholders.
- The tax savings go to ratepayers.

- The tax savings go to the shareholder.

Schools sponsored evidence by Dr. Mintz of the C.D. Howe Institute. Dr. Mintz, a tax expert, testified that tax savings in the specified situations should flow to ratepayers. In his view, to do otherwise would result in:

- ratepayers subsidizing the disallowed expenses;
- incentives being created to inappropriately alter the distributors capital structure or expenses to maximize the tax benefits;
- delayed repayment of the stranded debt; and
- a departure from competitive market results, whereby any reductions in actual taxes paid result in lower prices to consumers.

The Coalition of Issue Three Distributors (CITD)[1] sponsored evidence by Ms. McShane. Ms. McShane, a regulatory expert, testified that the tax provision for a distributor should be determined on the basis of the following principles:

- Benefits follow costs: the party bearing the cost should receive the tax saving.
- Stand-alone utility: only the costs and risks related to the utility operations should be in the revenue requirement.
- No harm to ratepayers: a "minimum" condition that specifies that ratepayers must be no worse off.
- Level playing field among gas and electricity distributors.

Applying each of these principles, Ms. McShane concluded that the tax savings in the specified situations should flow to the shareholder.

CITD adopted the position of Ms. McShane; namely, that in applying the regulatory principles and the government's objective of a level playing field, the conclusion is that the tax savings should flow to distributor and thus to the shareholder(s), rather than to the ratepayer. CITD maintained that this was accepted regulatory practice, and reflected that the tax savings arise from costs that the ratepayer did not bear.

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[1] The Coalition of Issue Three Distributors includes Aurora Hydro Connections Limited, Barrie Hydro Distribution Inc., Cambridge and North Dumfries Hydro Inc., Chatham-Kent Hydro Inc., ENWIN Powerlines Ltd., Guelph Hydro Electric Systems Inc., Halton Hills Hydro Inc., Hydro One Networks Inc., Innisfil Hydro Distribution Systems Limited, Kitchener-Wilmot Hydro Inc., Newmarket Hydro Ltd., Orangeville Hydro Ltd., Orillia Power Distribution Corporation, Tay Hydro Electric Distribution Company Inc., Toronto Hydro-Electric System Limited, Waterloo North Hydro Inc., Westario Power Inc., Whitby Hydro Electric Corporation.

Hydro One, PowerStream and Toronto Hydro supported the submissions of the CITD and highlighted certain points:

- The fact that under current government policy PILs is being used to pay down the stranded debt is not relevant to how the amount of PILs to be paid should be calculated. The fact that the province allows an expense to be deductible for tax purposes is a matter of provincial tax policy, not ratemaking.
- A distributor would generally not incur a disallowed expense, and therefore passing on a tax saving to ratepayers, that did not occur, would increase the inequitable treatment.
- Schools' proposal implies that a distributor would undertake activities that violate the *Electricity Act*, the *Ontario Energy Board Act*, the Affiliate Relationships Code and the *Municipal Act,* and that the Board should address these violations indirectly through the tax calculation rather than directly.

LPMA supported the principles identified by Ms. McShane, and submitted that in a normal regulatory environment LPMA would support Ms. McShane's conclusions. However, LPMA submitted that tax savings should flow to ratepayers because PILs are used to pay down the former Ontario Hydro stranded debt. The tax savings are therefore a "cost" to ratepayers. LPMA goes on to apply Ms. McShane's regulatory principles to come to the opposite conclusion of Ms. McShane. In LPMA's view, any tax savings is a cost to ratepayers, without any benefit in those cases where the cost is disallowed. LPMA concluded that if the Board were to decide that tax savings from disallowed expenses were not to go to ratepayers, then the Board should inform the government as to the negative impacts on ratepayers and the level of debt.

Conclusions

The Board finds that tax savings arising from the specified situations will not be allocated to ratepayers. The regulatory principles identified by Ms. McShane are applicable in this situation. What is at issue is how those principles are to be applied and whether there are sufficient grounds to depart from them in these circumstances.

Schools has argued, in effect, for a departure from these established regulatory principles for four primary reasons:

- If the tax savings are not allocated to the ratepayer, then the ratepayer is effectively "subsidizing" the disallowed expenditure.
- If tax savings flow to shareholders, then the shareholder, because it is a non-taxable entity, will have an incentive to use the distributor as a "tax shelter" and to incur expenses or alter the distributor's capital structure inappropriately. For example, there would be an incentive to finance the distributor with 100% debt.
- In a competitive market, any reductions in tax paid would generally result in lower prices.
- PILs payments are used to pay down the stranded debt. If tax savings go to the shareholder, then rates will be set with a higher provision for taxes than will actually be paid. Ratepayers will repay a certain amount of the stranded debt through the regulatory tax calculation, but the full amount will not be remitted as PILs because of further deductions by the distributor. In effect, the ratepayers will have to pay twice.

The Board does not believe that any of these arguments supports a departure from standard regulatory practice and established regulatory principles.

With respect to the first point, the Board does not agree that if the tax savings are not allocated to the ratepayer, then the ratepayer is effectively "subsidizing" the disallowed expense. Schools argued that if the distributor incurs the disallowed expense, then it would be inappropriate for the tax benefit to flow to shareholders (by being excluded from the rates). However, Schools agreed that if the shareholder incurred the disallowed expense within another (tax paying) entity, then it would be appropriate for the tax benefit to flow to the shareholder. Dr. Mintz also agreed with this. The Board finds this reasoning to be inconsistent with the claim that in one scenario the ratepayers are somehow "subsidizing" the shareholders; the level of taxes included in rates is the same in both scenarios. The issue remains as to whether the distributor has behaved appropriately in undertaking the disallowed expenses, and that issue is addressed under the next point.

With respect to the second point, the Board accepts that because municipalities are non-taxable, there may be an incentive to allocate expenses and adjust the capital structure of the distributor to maximize the tax advantages. However, there are limits on what actions can be taken. These limitations arise from various statutes, and are intended to ensure that customers are protected and the financial viability of the distributor is maintained.

Schools suggested that these limitations are not sufficient in the case of municipal distributors and maintained that preventing inappropriate behaviour by taking away the tax incentive is the "most elegant way to get the right result". The Board disagrees. The tax approach would require the Board to impute tax savings, which would then need to be adjusted if the expenditures did not occur. Alternatively, there would need to be an after-the-fact investigation of tax deductions to look for "disallowed" amounts. In the Board's view this is not "elegant". It is administratively complex, and still fails to get to the nub of the issue, which is the inappropriate behaviour. If a distributor engages in inappropriate activities, then the Board should address the matter directly.

Schools appeared to be particularly concerned about inappropriate social spending and capital structure changes. The Board is satisfied that section 71 of the *Ontario Energy Board Act* provides the requisite protection against inappropriate expenditures by a distributor. When the Board conducts its review of cost of capital and capital structure, it will consider in more depth the relationship between capital structure, interest expense and taxes and determine the appropriate regulatory framework. This issue is addressed further in the section on interest expense. The Board is satisfied that its provisions for tax information disclosure, addressed later in this section, will allow for adequate monitoring of these issues.

With respect to the third point, the Board accepts the evidence of Dr. Mintz that in a competitive market tax reductions will tend to lead to lower prices, but does not agree with his conclusion that the tax savings of disallowed expenses should be passed on to ratepayers. Such an approach takes no account of the increased expenditures from which the tax savings arise. Presumably in a competitive market, if an entity incurs a cost from which a tax reduction is gained, the increased cost works its way into prices as well. A unilateral allocation of the tax savings to the ratepayers would seem to be an inappropriately simplistic application of the competitive market principle.

With respect to the fourth point, the Board does not agree that the link between PILs and the stranded debt is relevant. All tax revenues are used for some purpose, whether to fund programs or repay debt. To the extent tax deductions are allowed, there will necessarily be a reduction in funds available for those other purposes. The relationship between PILs and the stranded debt is no different. This conclusion is supported by the fact that the express purpose of PILs was to put municipal distributors on an equivalent basis with tax paying distributors. The fact that PILs payments are allocated to the stranded debt is a function of provincial policy and is not necessarily a permanent feature. Finally, the Board notes that PILs from distributors are not the only, or largest, source of funds currently paying down the stranded debt.

For all of these reasons, the Board rejects the proposal by Schools, and concludes that tax savings arising from disallowed expenses, including purchased goodwill and charitable donations, will not be allocated to ratepayers. Ratepayers have not paid for the expense through rates, and therefore are not entitled to the tax benefit.

Fair market value "bump"

The Ministry of Finance required the re-valuation of distributor assets to market value, effective October 1, 2001. This Fair Market Value Bump, or FMV Bump, adjusted the value of distributors' Cumulative Eligible Capital or Undepreciated Capital Cost. No adjustments to rate base were made for regulatory purposes. There is a potential impact on the Cumulative Eligible Capital (or Eligible Capital Expenditures) deduction or the Capital Cost Allowance. With respect to the Cumulative Eligible Capital or Undepreciated Capital Cost, the issue is whether the tax savings arising from the FMV Bump should be shared between ratepayers and shareholders, allocated 100% to the ratepayers, or allocated 100% to the shareholder.

The positions and reasoning taken by each of the parties were largely the same for this issue as for the previous issue of tax savings arising from disallowed expenses.

CITD maintained that while no "cost" has been incurred, the tax savings would be subject to recapture if the assets are sold at fair market value, and therefore it is essentially a temporary benefit. Hydro One submitted that because the tax benefit is recaptured upon sale of the assets or change in tax status, ratepayers would have to compensate the distributor for that recapture if they are to benefit from the tax benefit. Schools essentially agreed that recapture of the benefit might occur and submitted that ratepayers should get the savings now, and that the Board should address the recapture at the time of the future transaction.

Conclusions

The Board finds that any tax savings resulting from the FMV Bump will be allocated to the ratepayers. It is true that the rates themselves are based on book value not market value, which suggests that under the stand-alone principle the FMV Bump should be disregarded. However, the shareholder has not incurred any cost related to the change in value for tax purposes (as CITD acknowledged), so the "benefits follow costs" principle is not applicable. In addition, the FMV Bump could be characterized as a change in the tax rules, and therefore would fall into the category of changes subject to true-up. Ms. McShane testified that the savings would be subject to recapture and Hydro One submitted that if the ratepayer benefits from the FMV Bump, it should also be liable for the recapture. The Board agrees that if the ratepayers benefit from this tax saving, then any subsequent recapture should be considered for recovery from ratepayers as well. However, the Board has no evidence as to how frequently or to what extent this recapture will take place.

While the Board cannot address the recapture at this point, it can address the current tax savings. The Board has determined that the 2006 tax calculation will incorporate the impact of the FMV Bump. If at some point a related tax liability arises from a sale of assets or change in tax status, then the distributor will be able to apply to the Board for relief, at which point the issue will be determined. The Board notes that this approach will reduce the variance between actual taxes and the tax provision in rates, that it will not disadvantage the shareholder because the shareholder incurred no cost, and, if there is subsequent recapture, the distributor may apply to the Board for relief.

Loss carry-forwards

The Draft Handbook requires the distributor to take into account the potential reduction in actual taxes payable where a loss carry-forward is applicable.

Hydro One submitted that any loss carry-forward resulting from revenue or expense variations in prior years was irrelevant for the 2006 tax calculation. It argued that the ratepayer has not contributed to the prior loss and therefore is not entitled to the future tax savings. Hydro Ottawa made similar submissions.

Conclusions

The Board has no evidence before it to determine whether loss carry-forwards are the result of revenue or expense variations or whether the loss carry-forwards arise for other reasons that may be related to ratepayers. The Board notes that the consensus approach will reduce the variance between taxes collected in rates and actual taxes paid. The Board will adopt this approach in the Handbook. However, the Board has concluded that a projection of this factor to 2006 will not be required as this represents unnecessary complexity for purposes of 2006 rates.

Interest deduction

At issue is the amount of the interest to be deducted for the regulatory tax calculation. The Draft Handbook contains four alternatives:

- Deemed (recoverable) interest expense
- Actual interest expense
- The greater of deemed (recoverable) and actual interest expense
- Share of additional interest expense (above the deemed level)

Currently, taxes are determined using the deemed interest expense, but the Board has previously indicated its intention to true-up this component of taxes to reflect actual interest expense, and the difference is being captured in the variance account.

CITD supported the first alternative, namely the deemed interest expense used for ratemaking purposes. EDA, Hydro One, Toronto Hydro, ECMI, NEPPA, Union, and CME were all of the same view.

Schools supported the third alternative, namely that the greater of the deemed or actual interest expense should be used. It relied primarily on concerns about the incentive for a distributor or its shareholder to adjust the distributor's capital structure to minimize taxes. LPMA made similar submissions.

Conclusions

Under the stand-alone principle, the level of interest used in the tax calculation should be the same as the deemed level of interest included as a distribution expense in the revenue requirement. However, the Board agrees that the incentive may exist to alter the capital structure in a way that substantially benefits the shareholder in terms of reducing actual taxes paid. The resulting difference between taxes paid and taxes collected through rates may be of sufficient magnitude to call into question whether the resulting rates are just and reasonable.

Contrary to Schools submission, the Board does not agree that the best way to deal with this issue is through the tax calculation. The Board should consider whether alternative capital structures (and associated tax implications) are appropriate, rather than just implement disincentives to deviate from the deemed capital structure. The Board's conclusion is that this issue should be dealt with comprehensively at the time of the capital structure and rate of return review (as described previously). As part of that review the Board will consider, among other things, the tax implications of various capital structure strategies and will determine the most appropriate overall approach for ratemaking purposes.

However, for purposes of 2006, the Board will continue the current treatment but refine it such that the tax calculation will be based on the greater of the deemed and actual 2004 interest expense, including the Tier 1 and 2 adjustments. Applicants will be required to file information regarding the actual debt ratio and interest cost.

Sharing of tax exemptions

The Draft Handbook states that the federal large corporation tax exemption and Ontario capital tax exemption will be prorated when multiple regulated entities are in the same corporate group. With respect to the prorating of any tax exemption between the distribution and non-distribution functions in the same legal entity, the Draft Handbook contains two alternatives: one alternative is to prorate; the other is not to prorate.

LPMA submitted that these tax exemptions should not be prorated amongst regulated entities within a corporate group. LPMA argued that to do so would violate the stand-alone principle, because if the distributor were stand-alone, then the full LCT exemption would apply. The result of the treatment in the Draft Handbook is that customers would face higher rates as a result of the corporate affiliates sharing the LCT exemption. Similarly, LPMA submitted that there should be no pro-rating of the exemptions between distribution and non-distribution functions.

Hydro One, Toronto Hydro, Union, CME and VECC all supported the pro-rating of the exemption between distribution and non-distribution functions.

Conclusions

The Board agrees that the stand-alone principle is applicable in this situation and that the federal large corporation tax and Ontario capital tax exemptions should be determined without a prorating between distribution and non-distribution functions. However, the exemptions will be prorated among regulated entities within the same corporate group. Although this is not a strict application of the stand-alone principle, it recognizes that there has been, and continues to be, consolidation among Ontario distributors. Given that those corporate structures are evolving and rate harmonization is not complete, the Board concludes that it is appropriate to recognize the shared nature of the resulting tax exemptions and that such an approach does not deviate from the intent of the stand-alone principle.

Undepreciated Capital Cost (UCC) and Capital Cost Allowance (CCA)

The Draft Handbook states that the CCA calculation in the OEB 2006 PILs model should be based upon 2004 actual UCC and the allowed Tier 1 and Tier 2 capital adjustments. The applicant is also to assume new additions in 2005 equal to 2004 capital expenditures. A similar approach is used to set the values for 2006. In effect, the UCC is inflated from 2004, based on additions in 2004 and the Tier 1 and Tier 2 adjustments, to create a proxy for 2006.

Hydro One submitted that the proposed adjustments would be inappropriate. In its view, the adjustments would result in the PILs calculation being based on a higher rate base amount than that used to determine the equity return and book depreciation. In its view, this would have the effect of reducing the shareholder's allowed equity return. Hydro One submitted that the base should be 2004 actuals plus any applicable Tier 1 and Tier 2 adjustments only.

Conclusions

The Board agrees that rate base and undepreciated capital cost (and therefore the capital cost allowance) should generally be determined on a consistent basis. The adjustments contained in the Draft Handbook could be characterized as a quasi-forward test year approach. The Board concludes that these adjustments represent an unjustified inconsistency with the determination of the other components of the revenue requirement for applications based on an adjusted 2004 historical test year. The Board will adopt the more simplified approach of using 2004 actuals plus any Tier 1 and Tier 2 adjustments. This approach would not be applicable to those distributors filing on a forward test year basis.

Regulatory assets and liabilities

A PILs or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their tax returns. The Handbook will reflect this treatment.

CDM and Smart Meters

The issue is how the 2006 regulatory tax calculation should take account of CDM and Smart Meters capital and operating expenditures. The Board addresses CDM in detail in Chapter 16 of this Report. To the extent incremental CDM and/or Smart Meter expenditures are approved, they will form Tier 1 adjustments and will be treated accordingly for purposes of taxes.

Tax information disclosure

The Draft Handbook requires the distributor to disclose the actual corporate taxes or PILs paid in 2006 and the amount collected in 2006 rates, with any differences greater than 10% to be explained in a future filing. At issue is whether a distributor that does not have a separate tax return for the distribution portion of the business should be exempted from this requirement.

Hydro One and ECMI supported the exemption. NEPPA argued that filing audited financial statements for the wires-only company might place unnecessary risk on a subsidiary business and that any filing, including supporting documentation, should be confidential.

Schools did not support the exemption and suggested that individual requests for exemption should be brought to the Board. The Board could then determine the appropriate means for disclosure.

Conclusions

The Board finds that the requirements will apply for all distributors. There must be transparency in the regulatory process. It remains open to a distributor to request an individual exemption, and the Board will consider such a request on its merits. It is also open to a distributor to request that tax information be kept confidential, and a determination would be made be the Board at the time the request is made.

CHAPTER 8: REVENUE REQUIREMENT

Chapter 8 of the 2006 Handbook address the transition from cost to revenue. A key point is that the applicant is responsible for recording its revenues in such a way that it avoids double recovery of its costs. There are a variety of charges that generate revenue other than the main distribution rates, and that revenue must be accounted for before the determination of the distribution rates can proceed. The methodology to be used in this process is outlined in this chapter of the Handbook.

The "Base Revenue Requirement" is defined as the "Service Revenue Requirement" less revenue offsets, which are revenues derived by the distributor from other Board-approved charges and from sources other than Board-approved charges. The Base Revenue Requirement determines the revenue to be raised from the main distribution rates.

Issues and Conclusions

Under the heading of revenue from Board-approved charges, NEPPA argued that the revenue from Miscellaneous Charges (Account 4235) fluctuates substantially and should not be considered. VECC submitted that a history of the revenue amounts would be useful, and suggested that a three-year average could be used in place of the 2004 amount. The draft Handbook states that the amount derived in Schedule 11-3 is to be used for Miscellaneous Revenue. The Board finds that this revenue should be considered. However, the Board finds that the three-year average of the number of transactions is more meaningful information than the average of the revenue. Using the number of transactions removes the volatility arising from changes in the transaction charges. The new transaction charges will be applied to the average transaction levels to determine the revenue.

Under the heading of revenue other than Board-approved charges, NEPPA argued that revenue from sources such as investments and bank accounts fluctuates and should not be considered. VECC disagreed that volatility should be considered an adequate reason to exclude the adjustment. The Board finds that revenue from investments and bank accounts must be considered as a revenue offset to calculate the Base Revenue Requirement. However, these amounts will not include interest earned on security deposits, in recognition that interest on these deposits is paid directly to ratepayers.

Schools argued that Tier 1 adjustments in general are mandatory, and Tier 1 revenue adjustments should not be optional. A Tier 1 adjustment must be made to 2004 revenue for unusual or non-recurring events, subject to the materiality threshold, regardless of whether the event caused unusually high or low revenue in 2004. Hydro Ottawa suggested that the materiality threshold should be based on total 2004 distribution revenue, rather than the revenue offset. The Board confirms that the Tier 1 revenue adjustment is mandatory, subject to the materiality threshold, if an applicant files on an adjusted 2004 historical test year basis. The Board further concludes that the materiality threshold for Tier 1 adjustments will be 3% of the 2004 revenue offset.

A small number of distributors play a role as host distributor, by the fact that part of the load on certain distribution facilities is delivered to another distributor. Energy Probe notes that Tier 1 adjustments (as contemplated in the Draft Handbook) are to be made to costs (ie. adjustments by embedded distributors) covering LV amounts prior to 2004, between 2004 and the 2006 rate period, and during the 2006 rate period. While the same level of detail is not provided to the host distributors, Energy Probe submits that the Base Revenue Requirement of a host distributor should be understood to be net of revenue derived from LV rates. VECC submits that only the charges approved by the Board for 2005 should be included in revenue adjustment.

The Board agrees that where a host distributor has an approved LV or wheeling rate, the expected revenue from that rate should be removed from the base revenue requirement before 2006 base rates are calculated. If a host distributor does not have an approved rate, it may seek approval of a rate as part of its 2006 rate application, and remove the expected amount of revenue from that rate from the base revenue requirement.

The draft Handbook leaves open the possibility that components of the revenue requirement attributable to CDM and Smart Meters might be allocated differently than the rest of the Base Revenue Requirement. Chapter 16 of this report addresses CDM issues in depth.

CHAPTER 9: COST ALLOCATION

The basic assumption for the 2006 rate process is that any major adjustments to the proportion of distribution revenue requirement that is assigned to each class, sub-class or group (i.e. cost allocation) be deferred to a future year when the load research results and the cost allocation methodology will be under review. In addition, any major modifications to customer classifications in the 2006 rate process may be premature. Therefore, the existing customer classifications are to be maintained, unless special circumstances are justified by a distributor.

The Handbook has been written such that the respective class distribution base revenue requirements will continue at approximately the same proportions of the total distribution base revenue requirement as in the initial design, with the exception of the treatment of specifically directed issues as identified in Chapter 8; namely, the recovery of regulatory assets, and certain CDM expenses.

This report addresses the following issues:

- customer classes
- determination of the appropriate share of the 2006 revenue requirement for each class, sub-class or group
- the adjustment of load relating to CDM programmes
- the adjustment of load relating to Smart Meters
- determination of the appropriate share of the 2006 CDM, Smart Meter, and regulatory asset revenue requirements

Customer classes

VECC noted that the reference in this section to “existing practice” is rather oblique and open to interpretation. It suggested that the Board should clarify what it considers the existing practice to be or, in the alternative, a distributor should be required to say what its practice is. In VECC’s opinion, this would prevent other situations like that of scattered and unmetered loads from arising.

Schools stated that the third paragraph of section 9.1 of the draft Handbook deals with distributors who wish to change their customer classifications. Schools submitted that while there may be many legitimate reasons why changes are necessary, it is also true that cost allocation and rate design are scheduled to be considered for 2007 rates, not 2006, and class changes in the absence of a disciplined look at cost allocation and rate design run a significant risk of being made on insufficient information. Therefore, Schools proposed that further clarification be added to the section.

NEPPA stated that, in the past, a distributor was able to reclassify a customer within the general service class depending on its demand. It assumed that this practice will continue to be allowed and that once changed the distributor is not obligated to review a customer's class for one year.

Conclusions

The Board confirms that the approach to be taken in 2006, as outlined in section 9.1 of the Handbook, is reasonable with respect to the retention of the existing rate classes, sub-classes or groups; the procedure to be followed if a distributor proposes to make any change to its customer classifications; and, the maintenance of the existing practice with respect to the billing of a customer that has a billing demand greater than 50 kW but is classified in the <50 kW sub-class and is therefore billed on kWh.

For further clarity, the following sentences will be added to this section 9.1 of the Handbook to incorporate some of the suggestions of Schools:

> Changes in customer classes, sub-classes or groups should only be undertaken if there are unusual circumstances in which a change is clearly immediately required. The Board intends to review cost allocation and rate design in the future, and an applicant should consider whether any changes to customer classes would be better incorporated into a more rigorous review.

In an attempt to reduce the apparent confusion regarding customer classification, the Board will require a distributor to include a description of the eligibility criteria used to determine a specific customer's rate classification as part of its application. This section of the Handbook will be modified to include this component and the material required will be included as a Schedule to the Handbook. The information contained in that schedule may be used as a component of the distributor's rate tariff.

Determination of the appropriate share of the 2006 revenue requirement for each class, sub-class or group

The Handbook outlines the procedure that will be followed to determine the appropriate share of the 2006 distribution revenue requirement for each class, sub-class or group. If a distributor thinks that the methodology or the charge determinants do not accurately reflect its circumstances, it can propose an adjustment, providing a detailed explanation and justification.

NEPPA supported the averaging of the kWh/customer and kW/customer data as the fairest method of dealing with weather normalization.

Schools submitted that the draft Handbook was not clear as to how the proposed default cost allocation between classes is supposed to track the allocation for either 2004 or 2005. It submitted that the narrative description does not provide sufficient detail to address whether the methodology will cause shifts between classes from 2004 or 2005 to 2006. It believed that a statement of cost allocation principle might be of assistance, not only in understanding the methodology, but also for distributors to understand where an adjustment might be appropriate. It suggested the following sentence be included in the first paragraph:

> The intention of this cost allocation model is to allocate costs to customer classes in the same proportions as costs were allocated on average in 2002 through 2004, but with adjustments where the number of customers or the throughput of any class has undergone a material change.

With respect to the fourth paragraph of Section 9.2, Energy Probe recommended using 2004 kWh/customer and kW/customer data for calculating the ratios of each class, sub-class, or group's dollar amount to the total for a distributor with a positive growth rate in

2003 and 2004. If growth rates are not positive in 2003 and 2004, it recommended that average kWh/customer and average kW/customer statistics should be applicable. LPMA submitted that the sentence should be amended to read, "These rates are then multiplied by the 2004 *year-end* class customer count (or connection count), ..." to reflect what was agreed to in the working groups in which LPMA participated. Similarly, in Schedule 9-2, the columns labeled 2002 Customers, 2003 Customers and 2004 Customers should indicate Year-End Customers in all cases.

With respect to the adjustment of the allocations to reflect a distributor's unique situation as outlined in the fifth paragraph of this section, LPMA implied that more specificity be provided in the Handbook and suggested a material proportion of distribution revenue be defined as 2%. Schools also noted that there is no materiality test for this section and also suggested that 2% of distribution revenues should be expressly set forth in this paragraph to make clear that this is a mandatory adjustment with a fixed threshold. VECC submitted that a materiality criterion is required with respect to a known/verifiable loss or gain of a major customer during/after 2004 and suggested that a 5% threshold would be reasonable, recognizing that load growth will to some extent offset the impact of customer losses.

Schools submitted that it was not clear how the adjustment for gains or losses of load, which is a Tier 1 adjustment, relates to the revenue adjustment in Chapter 8. It stated that it believed that Chapter 8 adjusted only for non-distribution revenue offsets and that adjustments driven by load were dealt with only in Chapter 9. It stated that this should be made explicit.

Schools was also concerned about the lack of detail in the reporting of load adjustments. In its opinion, these adjustments could easily have a larger impact on final rates than the adjustments to distribution expenses or rate base set forth on Schedule 3-2, yet little in the way of reporting appears to be required. It submitted that a new schedule, similar in content to Schedule 3-2, be added to require detailed reporting of these Tier 1 adjustments relating to load.

Schools also noted that the "gain or loss of a major customer" appeared to be limited to customers that are entirely new or are entirely gone. It submitted that the narrative be worded to include not only these occurrences but also significant changes in a continuing customer's operations that could have a material impact on 2006 rates.

Conclusions

In general, the Board confirms that the approach to be taken in the Handbook with respect to the allocation of distribution revenue requirements among the rate classes, sub-classes or groups is reasonable.

For additional clarity, the following additions to this section of the Handbook will be made:

- the sentence suggested by Schools will be included in the first paragraph of this section.
- the word "year-end" will be added as necessary.
- a materiality threshold of 2% of distribution revenue will be included with respect to the adjustment of the allocations.
- an explicit comment regarding the nature of the Chapter 9 adjustments to be driven by load.
- the wording concerning the gain or loss of a major customer will be amended to include significant changes in a continuing customer's operation that could have a material effect on 2006 rates.

The adjustment of load relating to CDM programmes

AMPCO submitted that given the state of development of CDM programmes this requirement should be deleted from the 2006 Rate Handbook. AMPCO stated that it understood that the purpose of the proposed forecast of decreased load is to shift the proportions of distribution expenses allocated to customer groups rather than acting as a Lost Revenue Adjustment Mechanism (LRAM) mechanism. However, it claimed that forecasts of CDM program impact are unlikely to be available by the date a distributor will have to make its 2006 rate application. It stated that the forecasts contemplated by this paragraph are more detailed than required for a prospective LRAM because they need to be by "applicable rate class, sub-class or group" and there is no reasonable expectation that these forecasts will be available.

LPMA also questioned the need for such an adjustment. It noted that such load losses are likely to be difficult to forecast, at best. In addition, if a distributor has an LRAM, the impact of the lost load will be recorded in it. LPMA noted that if an applicant reduces its load forecast for CDM programs, then this needs to be reflected in the LRAM calculation. It would only be the variance (positive or negative) that would flow into the LRAM account.

Conclusions

The Board has concluded that no load adjustments will be made for CDM programs for 2006 rates. Details related to the LRAM are contained in Chapter 16 of this report. As a result, the paragraphs referring to the load adjustments for these programs will be deleted from the Handbook.

The adjustment of load relating to Smart Meters

AMPCO submitted that a distributor is in no position to forecast the impacts of Smart Meters in time for its 2006 rate submission and therefore this paragraph is unnecessary for the 2006 Rate Handbook.

Schools stated that it was concerned that the applicants are not being given any guidance in the Handbook as to how to adjust load for impacts relating to smart meters. It submitted that given the lack of experience in this initiative and the varying levels of load forecasting expertise amongst the distributors, this approach would appear to create a potential for widely varying estimates of load reductions and therefore widely varying rate impacts.

Conclusions

The Board has concluded that no load adjustments will be made for Smart Meter programs for 2006 rates. As a result, the paragraphs referring to the load adjustments for this program will be deleted from the Handbook.

Determination of the appropriate share of the 2006 CDM, Smart Meter, and regulatory asset revenue requirements

A discussion with respect to the allocation of CDM costs appears in Chapter 16 of this Report.

Regarding the allocations of Regulatory Assets, Schools proposed that the following sentence be included: "It is the responsibility of each applicant to ensure that they apply for a Phase II regulatory assets order in time to implement that order when received as part of 2006 rates."

VECC stated that in the case of Regulatory Assets, rather than having each distributor determine the allocation treatment based on the Board decisions, it would be useful if the Board were to specify in the Handbook the allocation treatment required based on its December 2004 Decision.

Conclusions

Cost allocation of the 2006 incremental revenue requirement associated with CDM activities is dealt with in Chapter 16 in detail. In brief, the Board concludes that the direct operating expenses will be allocated to the rate classes, sub-classes or groups specifically benefiting from the activities. The capital and indirect or overhead components of the revenue requirement will be allocated across all rate classes, sub-classes or groups based on the respective share of distribution revenue.

For the allocation of the 2006 incremental revenue requirement associated with Smart Meter activities, the Board has concluded that the revenue requirement will be allocated across all rate classes (sub-classes or groups) based on the respective share of distribution revenue.

For the allocation of the 2006 incremental revenue requirement associated with the recovery of regulatory assets, the Board has concluded that the allocation treatment will be based on the Board's December 9, 2004 Decision with Reasons in the matter of Review and Recovery of Regulatory Assets – Phase 2.

CHAPTER 10: RATES AND CHARGES

Following the Board's direction regarding the primary focus of the 2006 EDR process, the Draft Handbook proposes that, for the most part, existing methodologies, practices, and procedures with respect to rate determination are to be maintained for 2006, pending the review of the cost allocation studies.

The draft Handbook proposes, subject to the recovery of new adders that may be specified in Board decisions, that the established ratios of the class (sub-class or group) revenues recovered from the fixed and variable components of the rates be maintained at more or less the same levels used in the start of the determination of the 2004 rates (i.e. as shown at the start of the 2004 RAM process, not the final 2004 splits). The Draft Handbook allows for a distributor to alter this methodology provided it includes a detailed explanation and justification for the modification.

This report addresses the following issues:

- fixed/variable split
- unmetered scattered loads
- the loss adjustment factor
- distributed generation
- standby charges
- the recovery of CDM, smart meter and regulatory asset revenue requirements

Fixed/variable split

Most distribution rates in the province have a fixed monthly charge to which is added a variable charge that fluctuates according to the amount of electricity used by the customer.

The dichotomy between the elements of the single distribution rate is based, at least in theory, on the split between the fixed costs governing the provision of distribution services and the variable costs associated with the delivery of power to the customer connection point. It has been observed that there is remarkable diversity throughout the province in the relation between the fixed and variable portions and that the theoretical underpinning of the two elements has become blurred. Some suggested that the fixed/variable split should be eliminated. They argue that it is hard to administer, incents inappropriately, and is confusing to the consuming public. This point of view was most forcefully expressed in this proceeding by Woodstock Hydro and the EDA. Over the years others have argued for fundamental changes in rate design, such as increasing variable charges to provide a stronger conservation price signal to end users.

Conclusions

The development of the 2006 Handbook is not the appropriate mechanism for the consideration of this initiative. As noted elsewhere in this Report, the Board will be engaging the industry in a rate design consultation, and it is in this process that any fundamental re-assessment of the current rate design will be explored.

Several parties observed that the RAM model applicable to 2005 rates alters the resultant fixed/variable split for most distributors. The Board observes that the 2005 RAM model did use the fixed/variable splits as prescribed in the 2001 RUD to allocate the final third of MARR, but recovered the PILs and Interim Regulatory Assets on the variable charge only. This resulted in a change to the proportion of the total revenue recovered from fixed and variable charges.

Notwithstanding the preceding, and also to reflect the recovery of PILs, the Board adopts the use of a fixed/variable split of revenue that was determined by the application of the rates shown on Sheet 5 of the 2005 RAM, as the basis for the rate applications for 2006.

Finally, the Board received a submission from Schools urging the Board to adopt a methodology that would have the effect of narrowing the diversity of practice throughout the process in setting the fixed/variable split. Schools' proposal would identify and adjust rates where the fixed/variable split varied materially from the provincial average. The Board will not adopt this measure in the Handbook. First, the 2007 cost allocation review will generate relevant data to be considered in further consultations. Second, the implementation of Schools' proposal would require the Board to wait until all distributors had filed their applications before determining the average split. The Board would then apply the average to each system and make the adjustment, which is fairly marginal. This adds delay and complexity to the 2006 rates process, which is not balanced by a genuinely material enhancement of the outcome.

Unmetered scattered loads

In the course of the consultation, and most particularly during the submissions made at Issues Day, the Board was apprised of the fact that there was a very wide inconsistency in the rate treatment of unmetered scattered load customers across the province. Unmetered scattered loads tend to be relatively low loads such as traffic lights, and cable television and telecom equipment. Because the treatment of these users has never been the subject of a focused review by the Board, there is no coherent guideline governing the rates to be charged to this group of customers.

As previously stated, the Board made it clear that the development of the Handbook in this process was not intended to address issues of cost allocation and rate design, which will be dealt with in future consultations. However the Board considered that it was appropriate to address this issue in some measure in this process, pending a more comprehensive review in the subsequent cost allocation and rate design consultations, and included this issue on the Issues List.

Affected parties with sharply divergent interests were able to arrive at an interim approach for the Board's consideration. That approach is outlined in Section 10.2 of the Draft Handbook. In the end there was very broad stakeholder support for the approach presented by the working group.

The proposed approach is not founded on accepted rate making principles. It is designed to limit the diversity in the treatment of these loads, to bring the monthly fixed charges into relationship with the General Service <50kW monthly charges, and to keep the distributors whole in the process. Any lost revenue attributable to the application of the approach is to be distributed across all rate classes in proportion to the distribution revenue contributed by the class to the overall revenue.

This last aspect raised some interest among some stakeholders. Schools in particular was concerned that the re-allocation of revenue requirement across all rate classes according to distribution revenue was inappropriate, and was inconsistent with accepted principles of sound rate making. Schools concern was somewhat mitigated by the fact that it is anticipated that the revenue re-distribution occasioned by the approach is expected to be very modest. Schools suggested that the Board should defer its acceptance of the interim approach until the full extent of re-allocation is known, at the time applications are filed.

Conclusions

Having considered all of the submissions made on this issue, the Board is persuaded that the approach developed by the working group and reflected in Section 10.2 of the draft Handbook should be adopted without amendment. The Board regards the proposal to be a reasonable interim measure pending a more comprehensive review of the rate structure for such loads. The Board recognizes that the proposal is not based on any particular rate making principles, but rather is an expedient measure designed to narrow the range of diversity in treatment of these loads pending further consultation. This is a supportable goal. The question of revenue re-allocation raises some concerns, but the Board is persuaded that the quantum is modest, and it is at least as likely that the unmetered scattered load customers have been over-contributing to the revenue pool. In the end, only a capable cost allocation and rate design effort can inform that question.

The Board notes that York Region addressed this issue in a letter of comment. The Region urged the Board to expand the application of the interim solution to all circumstances where a per-connection service charge is exacted. The Board is reluctant to expand the scope of the proposal beyond that which emerged from the working group, but the concern raised by the Region should be included in the upcoming cost allocation review, and the Region should be invited to participate.

Loss Adjustment Factor

A detailed discussion of loss adjustment factors is found in Chapter 16 of this Report. The draft Handbook proposes that the actual loss factors of a distributor are to be averaged over 2002, 2003 and 2004 to create the applicable loss factor for 2006 rates. The Board adopts this approach for 2006 rates. However, the level of line losses is a concern of the Board, and this concern is reflected in the additional filing requirements detailed in Chapter 16 of this Report and implemented in chapter 10 of the Handbook.

Distributed Generation

Distributed generation (DG) describes the phenomenon where a private interest develops, constructs and commissions electricity generation connected to a distributor's system, for the sole purpose of providing the electricity to the distributor. The creation of new generation is a key public policy initiative of the government. The orderly evolution of the power system in Ontario is dependent on the creation of new sources of electricity at reasonable cost. DG has the advantage of creating new sources of electricity and doing it in close proximity to where it is most needed, close to load. This avoids costs, present and future, associated with long or medium range transmission.

The issue presented for the Handbook concerns the extent to which the developer of DG ought to be credited with the transmission rates avoided by the distributor by reason of its projects.

Alternative 1 in the draft Handbook preserves the status quo and would not extend a credit related to avoided transmission costs to a DG developer. Alternative 2 would do so. A number of alternatives are embedded in Alternative 2.

The Board received submissions from numerous parties urging that the Board retain its current practice for the 2006 rate year, pending a better and more focused opportunity to consult on the complexities of the proposal for a credit to DG developers. Of primary concern is the effect that a rapid expansion of DG could have on the integrity of the transmission system. Proponents of this view suggested that DG facilities represent the erosion of load to the transmission system. Such erosion could lead to ever higher transmission rates for those who remain exclusively dependent on the transmission system. The suggestion was also made that the proposal contradicted the Board's decision in RP-1999-0044, the so-called transmission net billing decision.

Others, notably the DG lobby group and Pollution Probe argued strongly that the Board needed to take this opportunity to create the appropriate regulatory conditions for DG to progress. Proponents of this point of view suggested that the issue was not entirely novel, and that the power supply environment in Ontario calls for the facilitation of DG. They also suggested that the RP-1999-0044 case did not address the question of embedded generation, and that the proposal encoded in Alternative 2 therefore did not contradict the Board's findings in that case. Pollution Probe also noted that the status quo favoured single ownership sites over community-based generation initiatives. Customer –embedded generation sites are entitled to net billing treatment, but DG sites not so situated are not. Pollution Probe suggests that there is no good rationale for this difference in treatment, based as it is solely on the ownership of the site.

Conclusions

The Board concludes that it does not have a sufficient evidentiary basis upon which to provide the credit sought at this time. As indicated above, the orderly development of DG is an important element in the creation of a stable, effective and efficient electricity market in Ontario. This development should occur within a regulatory framework which is informed by all relevant factors. To this end, the Board will investigate the issues related to distributed generation, engaging stakeholders in that investigation.

Standby charges

Standby Charges are charges imposed by a distributor on a customer with load displacement facilities behind its meter to address the fact that the customer is dependent on the distributor for its entire electricity supply when the load displacement facility is out of service. The distributor must be appropriately compensated for maintaining the ability to accommodate the total load of a customer at any time. In determining the appropriate level of the standby rate, the Board must try to ensure that the recovery of costs associated with the distributor's facilities that must be available to meet the customer's total demand is not inadvertently subsidized by the rest of the distributor's customers and, at the same time, the customer with load displacement is not unduly burdened by higher than reasonable charges.

Conclusions

It is the Board's view that the most appropriate method of determining the standby rate involves a distributor-specific analysis (and in some instances a case-specific analysis) of the distribution costs that need to be recovered through the standby rate. Such analysis would reflect a more detailed direct assignment of costs.

Where a distributor currently has a standby charge, it should be continued for 2006. If a distributor determines that there is a need to introduce a charge or if a distributor wants to modify its existing charge, it must include such a request as part of its 2006 rate application, justifying the methodologies, levels and procedures to be used. The Handbook will include a sample methodology and framework that might be used as a basis for such an application.

The standby charge would be levied in a billing period applied only when the electricity is not supplied by the distributor (i.e. when the distributor does not supply electricity normally supplied by the load displacement facility).

Recovery of CDM, Smart Meter and regulatory asset revenue requirements

In accordance with the findings in Chapter 16 of this Report, a distributor may claim CDM operating expenses only for the 2006 year. As a consequence, it is important that these amounts, which will be incurred in 2006, but not continued into subsequent rate years, be identified. The Board therefore concludes that 2006 CDM operating expenses approved for recovery in 2006 will be recovered through a rate rider. This should facilitate adjustment of these amounts in future years. CDM capital expenditures, however, are to be treated in the same manner as other capital expenditures and recovered through base rates.

Smart Meter expenditures will generally be recovered through base rates. The Board presumes that distributors will have ongoing expenditures related to Smart Meters. If, however, any expenditures are a one time operating expense that will not be repeated in subsequent years, the applicant should state this fact in its summary of the application.

Regulatory asset amounts will continue to be collected in a rate rider.

CHAPTER 11: SPECIFIC SERVICE CHARGES

The Draft Handbook proposes the establishment of a set of well-defined Specific Service Charges that could be provided by a distributor. It anticipates that all distributors apply the basic set of services uniformly and that there should be no difference in the application of these services among distributors.

The methodology outlined in the Handbook for the establishment of Specific Service Charges consists of three options. Each progressive option becomes more complex and demands more explanation/justification by the distributor.

A fourth option, which does not require Board approval because it is not a rate or charge, is also outlined. It permits the distributor to bill the actual cost, on a time and materials basis, for a particular activity or to pass through third party costs.

A limited number of parties (Hydro Ottawa, NEPPA, VECC and Hydro One Networks) provided submissions on this chapter. Both Hydro Ottawa and NEPPA supported the principles and methodology outlined in the draft Handbook in general.

Hydro Ottawa, however, was concerned that the standard rates were developed without a fully allocated cost approach and as a result the burden rates used were significantly lower than reasonable. In its reply submission, VECC acknowledged and shared Hydro Ottawa's concern. VECC stated that this was a shortcoming that should be addressed in future distribution rate processes, particularly after the completion of the cost allocation review.

Hydro Ottawa was also concerned about the last paragraph in section 11.6, which indicates that distributors still need approval of the Board for services provided in competition with other service providers and that such a requirement will result in a loss of "competitive advantage". Hydro Ottawa recommended that the last paragraph of section 11.6 be removed. In its reply submission, VECC disagreed. It noted that Hydro Ottawa had acknowledged in its submission that the prices offered for such services must cover costs, otherwise distribution customers were subsidizing these activities. In order to demonstrate that cross-subsidization was not occurring, a distributor would have to either submit the rates for approval by the Board or perform the work on a full cost recovery basis as outlined in the second last paragraph of Section 11.6.

VECC also suggested that all formula-based charges that are materially different (i.e., 10%) from those currently approved should be supported by a variance analysis that explains the basis for the change.

Other matters and areas of concern have been identified during the 2006 EDR process regarding Specific Service Charges. In particular;

- whether there needs to be a restriction on the use of option four to those activities that are provided on a one-time basis and/or that involve unique specific activities or costs,
- the application of "after regular hours" charges and whether the use of this level of charges should be restricted to emergency situations or instances when the customer has requested that the service be completed at that time,
- the inclusion of a basic charge for "Power Quality Inspection" and the determination of the appropriate standard level of charge, and
- the incorporation of the Board's Decision and Order (RP-2003-0249) regarding the adoption of an annual province-wide usage charge relating to the use of a distributor's facilities by telecommunication and cable companies.

With respect to the second item, VECC stated that it might be impractical for the Handbook to specify what "after hours" are for all distributors. However, as a matter of principle there should be at least 40 hours per week where service is available at the standard price, and a distributor should be required to specify in its application what these are. Also, charges for after hours should be limited to instances where the customer requests "after hours" service. Emergencies related to safety or reliability should not be billed at higher after hours rates.

With respect to a Power Quality Inspection charge, Hydro One suggested there should be such a charge. It suggested that similar to the meter dispute charge, a standard charge should be applied for power quality inspections only when the source of the complaint is within the customer's plant, and the level of charge should be as follows:

• Basic Service Call (initial assessment)	$30
• Engineering Investigation (detailed investigation)	Time & Materials

In its reply submission, VECC stated there should be no charges for power quality inspection, unless the problem is one caused by the customer and is the customer's responsibility to resolve.

Conclusions

The Board concludes that there is no need for either a fully allocated cost approach to establish the levels of Specific Service Charges at this time, or for a variance analysis for all formula-based charges that are materially different from those currently approved. The Board also concludes that the approval by the Board of the Specific Service Charges referred to in section 11.6 of the draft Handbook will be required.

Regarding the fourth option identified in the Handbook, despite the lack of a need for Board approval for these charges, the Board will require a distributor that incorporates this approach to maintain records that demonstrate that the actual cost was billed to the customer. The Board will not place a restriction on the use of option four only to those activities that are provided on a one-time basis and/or that involve unique specific activities or costs.

With respect to the application of "after regular hours" charges, the Board agrees with the submission of VECC that, as a matter of principle, there should be at least 40 hours per week where service is available at the standard price and a distributor will be required to specify in its application what these are. Also, charges for after hours will be limited to instances where the customer requests "after hours" service. Emergencies related to safety or reliability will not be billed at higher after hours rates.

The Board is not convinced of the need to include “Power Quality Inspection” as a basic Specific Service Charge at this time, and will leave each distributor to include such a charge in its application with appropriate cost justification analysis, if considered necessary.

With respect to the incorporation of the Board's RP-2003-0249 Decision and Order, the Board concludes that the annual charge identified in that Decision and Order should be included as an approved Specific Service Charge in a distributor's rate application.

In conclusion, the Board agrees that the principles and methodologies as proposed in the draft Handbook, with the inclusion of the annual charge for pole attachments, are acceptable. The Board further notes that this approach does not prohibit a distributor from making an application for unique Specific Services Charges or levels of charges. Any distributor-specific charges, however, will require adequate justification by a distributor.

CHAPTER 12: OTHER REGULATED CHARGES

On Issues Day the Board concluded that the SSS Administration charge or retailer-service charges should not be reviewed in the 2006 EDR process. As a result, the Draft Handbook basically maintains a status quo approach for 2006 for the Other Regulated Charges identified in this Chapter. A limited number of stakeholders provided submissions on this chapter.

NEPPA submitted that the standard charge of $0.25 per month per customer has proven to be too low and does not adequately cover the existing costs. NEPPA further submitted that for the most part the Retail Service Charges are fair and reasonable, except that the costs for the EBT transactions are not adequately accounted for. It recommended that these costs should either be passed on to the retailers directly or to the customers requiring the service.

VECC was concerned that many of the Retail Service Charges are not cost based and objected to the wording in the Handbook, which suggested they are. It recommended that, at a minimum, the Board should commit to having these charges reviewed as part of the upcoming cost allocation review. Similarly, Union submitted that the charges related to the administration of the SSS (renamed to RPP), retail service charges and non-competitive electricity charges appear to have been set without detailed costing support. It stated that such an approach might be appropriate during a period of transition, but that these charges should be supported by an appropriate level of costing support as soon as it is practical to do so.

With respect to a fee for specific Service Transaction Requests, Hydro Ottawa submitted that the $2 charge is not appropriate for requests for customer information that exceed the two free requests provided each year. It claimed that this level of charge would cover only a small fraction of the cost of providing this service outside of the EBT system. It recommended that this charge should be considered under Chapter 11 Specific Service Charges as part of an information delivery charge and a distributor should be permitted to seek approval for a charge that reflects the cost of providing this service. In its reply submission, VECC agreed with Hydro Ottawa's submission.

In addition, Board staff identified an area of concern regarding the SSS/RPP Administration Charge with respect to its application with sentinel lighting and street lighting accounts on either a per connection or a per account basis. Staff asked if the Handbook should be more specific as to the application and if so what should be the basis of the charge.

Conclusions

With respect to the fee for specific Service Transaction Requests being considered under Chapter 11 Specific Service Charges as part of an information delivery charge, the Board notes that the proposed list of standard Specific Service Charges in Chapter 11 of the Handbook includes a charge for a request for other billing information, which may address the concern of Hydro Ottawa.

With respect to the application of the administration charge to sentinel lighting and street lighting accounts, the Board suggests that a distributor follow the same practice that it applies to the application of the monthly service charge component of the regular distribution rates.

Given the Board's conclusion on Issues Day not to review these charges, the Board concludes that the maintenance of the status quo for the 2006 rates identified in this chapter is appropriate. Some of these matters may be considered during the 2007 cost allocation review.

CHAPTER 13: MITIGATION

The evidence that the Board heard on this subject focused on two distinct concepts. Mr. Harper and Ms. Poon, who had been retained by VECC, suggested that the Board require a distributor to enhance the depth and detail of its supporting evidence where rates were to rise beyond certain thresholds.

Mr. HasBrouck and Mr. Hiedell, testifying on behalf of Hydro One, emphasized the importance of recognizing that whatever else may be said, a distributor needed to be confident that its reasonable costs incurred in providing service were going to be covered, together with a reasonable rate of return on equity. Mitigation efforts which compromised this recovery and return on investment threaten the viability and sustainability of the franchise.

Conclusions

The Board found value in both of these presentations.

The Board's ratemaking process is designed to establish a package of rates which enables the distributor to recover its reasonable costs of operation and, where applied for, the permitted rate of return on equity. This process fulfils the Board's statutory obligation to establish just and reasonable rates. The process is technical and objective and is not intended to create abundant elasticity in rate levels.

Notwithstanding that, it is important that the Board and distributors maintain a high level of diligence in assessing, and where possible, addressing circumstances where the rate setting process results in customer bill increases which may be thought to cause hardship to groups or classes of customers. This diligence is required both with respect to rate increases caused by the application of the rate model, that is through the Handbook, and in situations where a distributor is attempting to harmonize rates between consolidated distribution franchises.

The discussion and methodology outlined in this section is relevant and applicable to both rate harmonization proposals and proposed rate increases.

The Board considers that diligence respecting rate increases is a core responsibility of the distributor. It is a fundamental element of customer relations to manage the expectations of consumers and to remedy, where possible, and to the extent reasonable, hardship occasioned by material increases in rates.

It is important to recognize at the same time that there are limitations on the ability of a distributor to cure these situations.

First, a distributor has to act in a manner that is non-discriminatory as between individual customers and classes of customers.

Second, a significant portion of the customer bill derives directly from the price of the commodity itself, and other elements that are beyond the control of the distributor. The distribution charges, which are set by the Board through the Handbook process currently, represent approximately 25% of the bill received by customers.

The Board sees its role in this subject area as providing direction to the a distributor in its efforts without prescribing any particular mitigation methodology or response. Mitigation proposals will need to be considered on a case-by-case basis. There is no compelling single methodology that can equitably address all of the situations that may arise.

The first area in which the Board will provide direction concerns a threshold or action level beyond which the distributor will be obliged, as part of its rate filing, to outline its mitigation plan respecting an impacted class or group of customers.

The Board considers that the appropriate action level should be based on the total amount of the electricity bill (comprising commodity, distribution and regulatory charges) and that the threshold should be set at a 10% increase over the previous total bill.

While the distributor can address only the distribution charges element of the bill, it is the raw effect of the increase as a whole that concerns the affected group or class of customers. While the distributor may not be able to devise an equitable mitigation approach that resolves the customers' hardship, the Board concludes that this level of overall bill increase calls for assessment and scrutiny.

Accordingly the Board will require that distributors file with their 2006 rate applications mitigation plans for any class or group of customers as defined in the Handbook whose total electricity bill is expected to increase by more than 10% over the previous bill amount. The 2006 EDR Model will calculate bill impact assuming a constant commodity cost and other delivery charges. The mitigation plan must identify the affected class or group of customers, stipulate the rate applied for which gives rise to the action level and document the distributor's approach, if any, to address the increase. The application filed by the distributor should include the effect of the mitigation measures.

The Board recognizes that a distributor may determine in the course of the development of its mitigation plan that there is no equitable manner in which to resolve the bill increase. Such a finding by the distributor must be stipulated in the mitigation plan and supported with sufficient evidence.

The transparency and completeness of mitigation plans is of key importance, both to customers whose rates are being assessed because they exceed the threshold, and to all of the other customers of the distributor whose rates may be directly or indirectly impacted by the mitigation plan. As a general rule, the Board does not favour mitigation plans which are dependent on imposing otherwise unwarranted increases on one customer class in order to reduce increases for another. Adjustments within a class of customers are much more acceptable, such as changes to the fixed/variable splits which may have the effect of reducing bill impact.

The Board also considers that mitigation plans that are predicated on reductions in the revenue requirement are problematic. Revenue requirement reductions should inure to the benefit of all customers within the franchise, and should form part of the basic rate application, not a response to hardship cases. It is important that a distributor not compromise its overall ability to deliver reliable service to the service area in order to address discrete instances of hardship.

A distributor may choose to reduce its regulated rate of return in order to address situations requiring mitigation plans. This approach may be a useful tool in dealing with hardship increases. Such a course of action should be prudently considered in light of the medium and long-term financial health of the organization and its ability to provide reliable service.

As indicated earlier, it is not intended that the Board prescribe the specific methodology to be used to mitigate hardship increases. Individual panels of the Board considering the rate applications will have to make judgements on a case-by-case basis taking all of the circumstances then prevailing into account, but the principles outlined here are likely to guide their acceptance of any proposed mitigation plan.

A distributor who has a merged, acquired, or amalgamated service area, and who have not yet fully harmonized the rates between or among the affected distribution utilities or service areas, may file a rate harmonization plan. The plan must include a detailed explanation, justification, implementation plan and an impact analysis.

In the event that the combined impact of 2006 electricity distribution rate increases and harmonization effects result in total bill increases for any customer class exceeding 10%, the applicant should include a discussion of proposed measures to mitigate any such increases in its mitigation plan.

CHAPTER 14: COMPARATORS AND COHORTS

Opinions of the Experts

Three expert witnesses testified on the topic of comparators and cohorts: Mr. Robert Camfield, called by Board staff; Dr. Mark Lowry, called by Hydro One; and Mr. Tom Adams, called by Energy Probe. Each of the experts supported the general idea of using a comparators and cohorts (C&C) mechanism as a screening tool for the 2006 rate applications, but cautioned that the mechanism was not suitable for gauging overall distributor performance.

Mr. Camfield's main findings were:

- Significant statistical relationships exist between distributor costs, cost drivers & output quantities.
- There is a considerable level of inconsistency in the data.
- The C&C mechanism as proposed is feasible for use as a screening tool, with the caveat that the data must be of reasonable quality.
- Mr. Camfield agreed that the C&C analysis will not be useful in identifying distributors who are underspending or have a record of poor reliability.

The main thrust of Dr. Lowry's evidence was to recommend caution and the use of considerable care in introducing any kind of benchmarking, as unfair or inaccurate benchmarking can increase the operating risk of distributors. He recommended several methodological adjustments to Mr. Camfield's proposal, which Dr. Lowry believed would increase the accuracy of the analysis. Both these experts agreed that the number of cohorts that will be useful is something that will be driven by the results of the data analysis, although the cohort estimation will be influenced to some extent by the initial number, effectively an upper limit, chosen by the researcher.

Mr. Adams proposed that the Board give a clear message that the process of comparing Ontario distributors would not stop at devising a screening tool, but would develop into full benchmarking, possibly using a yardstick or efficiency frontier approach. He believed that two or more cycles of utility benchmarking would be needed to create a widely accepted system of assessing distributor efficiency. Mr. Adams suggested that the experience of other jurisdictions, especially the United Kingdom, could provide guidance for Ontario in proceeding towards full benchmarking. Mr. Camfield and Dr. Lowry did not agree that the United Kingdom experience was particularly applicable to Ontario.

All the experts agreed that, at this time, the measurement of capital would be a problem in conducting the C&C analysis. Dr. Lowry suggested that capital stock be excluded from the analysis, but Mr. Camfield argued that it should not be eliminated, as it is such a significant component of distributor costs and also influences expenses. He proposed several alternatives to deal with the problem of capital measurement. The evidence suggested that capital must be accounted for in some way if operating expenses are to be examined, as substitution between capital and operating costs is often possible. Mr. Camfield's proposed methodology does take account of the possibility of substitution.

The experts each provided a set of data filing requirements that they believed were necessary to enable the analysis to be performed. Much of this data are already filed by distributors under the Board's Reporting and Record Keeping Requirements (RRR). Mr. Camfield and Dr. Lowry agreed that an appropriate balance must be found that does not over-burden dsitributors with filing requirements but still facilitates the analysis. Mr. Camfield was of the opinion that a useful mechanism for screening could be constructed without perfect data, and accepted that the data received for the planned analysis would not be ideal.

Mr. Camfield indicated in his evidence that Hydro One Networks and Remote Communities would be excluded from the analysis due to their unique business context and institutional framework. He also entertained the possibility that other distributors would be excluded on the basis of the analysis. Dr. Lowry testified that the statistical clustering analysis proposed should produce statistics that indicate how far a given member of a cohort is distant from the mean of the cohort, and this may lead to consideration of exclusion of some distributors from the analysis. Dr. Lowry believed that it was plausible that both Hydro One and Toronto Hydro may be excluded from the analysis.

The witnesses were asked about the benefits and detriments of public disclosure of the results of the analysis and whether a distributor's customers could make any use of the results. Mr. Camfield was not opposed to public disclosure, although he acknowledged that there is a danger that distributors will be inappropriately branded as inefficient. Conversely, some distributors will benefit in being labelled as efficient. Mr. Camfield believed that consumers are likely more interested in prices than in costs, so the gap between costs and prices would have to be bridged to make the C&C analysis relevant to consumers.

Mr. Adams supported full disclosure of the data and the results of the analysis, arguing that monopoly distributors are entitled to very limited privacy with respect to their finances and operational plans and that customers can be empowered through the disclosure of information. He believed that the distributors could rely on the results of the cost analysis to explain price variation to consumers.

When asked about the future use of benchmarking for Ontario distributors, Mr. Camfield suggested that the Board should move towards benchmarking, i.e. a composite measure of performance, but noted that there is considerable work to be done to move from the proposed comparator and cohorts mechanism to true benchmarking. For example, the Board would need to deal with data consistency, measures of capital, service quality measures and the weighting of service quality measures in terms of value to customers. Mr. Adams also supported continuing work in benchmarking, and emphasized that the distributors need to participate in this initiative.

Conclusions

Four issues need to be addressed:

- Should the C&C methodology proposed by Mr. Camfield be used to screen the 2006 rate applications?

- If so, what is meant by "screening"?
- What data are required?
- To whom will the data and the analysis be provided?

Mr. Camfield's C&C Methodology

With respect to the first issue, the Board has concluded that it will use the C&C methodology proposed by Mr. Camfield and a description of the methodology will appear in the Handbook. The Board must find effective and efficient methods for assessing rate applications for over 90 electricity distributors. Administrative concerns regarding the volume of applications are important, but the need to find a technique to assist in establishing just and reasonable rates is even more important. The C&C method proposed by Mr. Camfield, while experimental, represents an appropriate development for the Board to pursue as it explores and considers various methodologies to assist in setting just and reasonable rates.

Although Dr. Lowry had some general concerns regarding the application of the C&C analysis and some specific concerns regarding the techniques to be used (for example, around capital), he was not opposed to its use as a screening tool for assessing the 2006 rate applications. The same was true of Mr. Adams. The Board notes that Mr. Camfield largely agreed with Dr. Lowry's concerns and indicated that he intended to make adjustments to the analysis, for example combining settlements and customer service. The Board is aware of the technical challenges involved, some of which were discussed by the experts. The Board accepts that developing these types of techniques will take time and will involve significant technical effort. However, the Board remains of the view that this is the appropriate direction to take in the rate regulation of Ontario electricity distributors.

In general, most stakeholders supported some form of C&C analysis for screening 2006 rate applications. Many identified C&C as a good first step towards benchmarking. PWU, Schools, Energy Probe and Hydro One each made specific proposals for how C&C should be conducted.

PWU submitted that service quality must be included in the analysis. The Board agrees that service quality is a relevant consideration, and also agrees with PWU that the Board cannot rely on the current service quality data for the C&C analysis. The Board does not believe that this shortcoming is sufficient to preclude the use of C&C as proposed for purposes of 2006 rate applications. Further work on service quality will be undertaken as the Board develops its analytical techniques.

Schools suggested an approach based on comparing the current rates. Energy Probe supported this proposal. The Board agrees that comparing rates is intuitively attractive, but such comparisons are far too simplistic to be of much use for screening rate applications. As submitted, these blunt comparisons may identify differences that can be explained by a wide variety of reasons: rate structure, operating circumstances, costs, etc. The C&C analysis will be more focussed on cost variations and will therefore be a more valuable analytical tool for screening 2006 applications.

Energy Probe urged the Board to endorse benchmarking and to consider its application as early as the 2006 rate process. It recommended that a working group examine and attempt to resolve technical analysis issues. The Board agrees that it can benefit from the expertise of others in developing its analytical techniques. However, for purposes of 2006 rate applications, the Board does not think it is practical or necessary to debate and resolve the details of the analysis beyond what Mr. Camfield has already described. The Board will leave Board staff to work with Mr. Camfield to develop the analysis. Further cooperative work for future development of benchmarking and/or other techniques may well be appropriate.

Hydro One submitted that it should be excluded from the C&C analysis, although it supported a technical comparative analysis. Others, including Energy Probe and ECMI, submitted that Hydro One should not be excluded from the analysis a priori. The Board has concluded that there is no compelling reason to exclude any distributor from the analysis in advance. The Board does accept that the analysis may indicate that there is no appropriate cohort for a particular distributor or distributors.

Screening

With respect to the second issue, a number of stakeholders expressed concern as to what "screening" would actually entail. Mr. Camfield and Dr. Lowry both indicated that the analysis should be used to identify which distributors should receive closer scrutiny. Mr. Camfield cautioned that the analysis itself was not an indicator of the level of efficiency of a distributor. The Board takes this to mean that the analysis cannot be used for any form of benchmarking for rate setting purposes and that the analysis is not evidence as to the prudence of a particular expense level. Specifically, the Board understands that although analysis may identify an average level of spending, it would be incorrect to draw the conclusion that any particular level represented an "efficient" level of spending. Further, the analysis itself is not evidence one way or the other as to the prudence of a particular level of expenditure.

Distributors submitted that once the analysis was done, the analysis itself should be put aside and should not be used as evidence within a proceeding. While the Board cannot limit in advance of a particular proceeding what evidence will be presented, the Board expects that the analysis itself would be of little probative value in determining the appropriate level of a particular expense. A distributors with expense levels that are "outliers" will have the opportunity to justify the expense(s). The Board recognizes that the analysis is experimental and that the data and/or the methodology may be unreliable. A distributor may wish to introduce alternative analysis that supports a different comparative conclusion. However, the Board would caution that it has already indicated that comparative analysis is not determinative of prudence. Challenging the analysis will not be sufficient to fulfill the distributor's obligation to demonstrate that the level of expense is appropriate.

Data Requirements

The third issue relates to the data requirements. The extent of the potential data requirements is of serious concern to the distributors. It is also of concern to the Board. The Board's objective is to make the collection and reporting of data as efficient, accurate and consistent as possible. Each of the witnesses, Mr. Camfield, Dr. Lowry and Mr. Adams, testified as to the appropriate data to be provided. Most of the proposed data are already filed through the Reporting and Record-keeping Requirements (RRR), although some additional data were recommended. The Board has determined that the RRR data will form the basis of the C&C analysis. As discussed elsewhere in this report, the Board intends to use the RRR as the basis of the application process as well.

Publication of the Analysis

What remains to be concluded is whether the data and analysis will be publicly available. The Board has concluded that the analysis will be made available publicly. Some distributors have identified a number of risks, primarily related to public credibility and reputation arising from misleading or misinterpreted analysis, and ECMI went so far as to identify a risk to financial integrity and viability. The Board sees no evidence to support this more extreme claim.

Rates must be set through a process which is fair, open and transparent – not just to distributors, but to all stakeholders. LPMA pointed out that the process would not be transparent if only Board staff and individual distributors have access to the analysis, and the Board agrees. In any event, the application data will be public and there is nothing to stop an intervenor from undertaking some form of comparative analysis. The Board can see no basis on which to conclude that such analysis should be confidential. The Board does not believe the concerns regarding reputation and credibility outweigh the requirement for a fair, open and transparent process.

The Board will ensure that the analysis contains the appropriate caveats in light of its experimental nature. The Board will emphasize that initial application of the C&C analysis in the 2006 rate setting process is exploratory in nature and that the analysis is not intended to be a comprehensive or definitive analysis of distributor efficiency. The fact that a distributor has high costs relative to others in its cohort does not necessarily indicate inefficiency on the part of that distributor.

The Board notes PowerStream and Enersource's request to have the analysis available in advance of the filing deadline for applications. The Board agrees that this would be beneficial and will attempt to accommodate that timing.

CHAPTER 15: SERVICE QUALITY REGULATION

The Board requires that an applicant file with its rate application the annual summary of Service Quality Indicators. The Service Quality Indicators (SQIs) and their measurement and reporting have not been altered in anticipation of the rate application process, other than as the result of specific Board decisions.

However, since the SQIs were developed in 1999, Ontario Regulation 22/04 has been proclaimed in force, and the Utility Advisory Council, working with the Electrical Safety Authority, has developed a "Guideline for Excavating in the Vicinity of Distribution Lines". The Regulation requires electricity distributors to respond to cable locate requests within a reasonable time. The Guideline indicates that the distributor shall make every reasonable effort to respond to notification requests and provide locates within 5 working days of notification. This five day standard may be shortened to two or three days as discussions at the Utility Advisory Council proceed.

Adherence to the standards set out in Regulation 22/04 is a legal requirement. The guidelines developed in consultation with the Utility Advisory Council received broad utility input. Distributors are reminded that the Service Quality Indicators adopted by the Board represent minimum standards and were put in place by the Board to measure distributor performance over time. Under no circumstances should the SQIs be interpreted to suggest that the OEB is authorizing a distributor to deviate from prevailing safety or engineering standards, standards set by law, or standards contained in guidelines developed by other authorized regulatory agencies. The question of consistency between reported SQIs and technical and safety standards will be considered by the Board in its next review of its SQIs.

CHAPTER 16: CONSERVATION AND DEMAND MANAGEMENT

Virtually all Ontario electricity distributors now have some experience with preparing conservation and demand management (CDM) programs given their applications related to the 3rd tranche of incremental MARR (3rd tranche). Over $163 million has now been committed over a three-year period in that exercise. The testing related to those programs was necessarily limited. Detailed reporting requirements were however required.

The 2006 EDR Handbook must address the procedures relating to expenditures beyond the 3rd tranche amounts and define the tests that will apply. These procedures should recognize the Government's commitment to reduce consumption in Ontario. To further this commitment, this Board, the distributors, the Ontario Power Authority (OPA) and other interested parties must develop well-defined procedures to approve, monitor and audit these expenditures.

Five expert witnesses testified on CDM matters:

- Mr. Paul Chernick, President of Resource Insight, on behalf of Green Energy Coalition (GEC);
- Mr. Jack Gibbons, President of Public Interest Economics, on behalf of Pollution Probe;
- Mr. A. J. Goulding, President of London Economic International LLC, on behalf of Ontario Energy Board staff;
- Mr. David Heeney, President of IndEco, on behalf of the Canadian Energy Efficiency Alliance (CEEA); and
- Mr. Roger White, President, Energy Cost Management Inc., on behalf of ECMI clients.

This report addresses the following issues:

- cost effectiveness
- expenditure levels

- lost revenue protection
- shareholder incentives
- treatment of expenditures
- distribution line losses
- cost allocation
- auditing and reporting

Cost Effectiveness

It was clear that most parties favoured the Total Resource Cost (TRC) test as a means of evaluating the costs and benefits of CDM programs, including calculating the incentive returns. Pollution Probe strongly supported the pre-approval of TRC inputs. Mr. Gibbons noted that the distributors have clearly indicated that they need regulatory certainty. Accordingly, they need pre-approval of their inputs so that they can be assured that their programs will be acceptable to the Board.

The EDA supported the Pollution Probe approach and noted that Mr. Heeney agreed that inputs such as measure life, free ridership rates and savings per measure should be pre-approved. Mr. Goulding also agreed that the Board should pre-approve distributor inputs. Pollution Probe disagreed, however, with his assumption that the Board should accept estimates provided by organizations such as the Canadian Electricity Association. Pollution Probe recommended that the Board independently develop these inputs.

Most parties supported the view that the Board should provide a Conservation Manual. The PWU specifically pointed to the Energy Policy Manual produced by the California Utility Public Commission referenced in the CEEA's evidence. The CEEA noted that the Board should develop a Conservation Manual that identifies a set of default methodologies and data that the distributors may rely on for their analysis and reporting to the Board.

Conclusions

The Board recognizes and agrees that pre-approval of inputs is essential as is the specification of the TRC test. To this end, the Board has in a previous Decision ordered Hydro One to produce avoided cost estimates by June 30, 2005. The Board has also undertaken an independent study that will generate data regarding the energy savings for a number of standard programs as well as estimates of measure lives and free rider rates. The Board will publish this data in a Conservation Manual. To the extent possible, the Conservation Manual will be similar to that issued by the California Public Utility Commission. It is expected that this Manual will be available in time for the rate applications by the distributors.

Expenditure levels

A number of parties considered whether the Board should establish a target level of CDM spending. CCC recommended that the government in conjunction with the OPA should determine the level of annual spending. It stated that the Board should not mandate a level of spending without a clear understanding of the benefits to be derived from that level of spending. CCC cautioned against unlimited spending on CDM even if the initiatives pass the TRC test, as this would not consider the overall impact on rates, which may be significant given a high level of spending.

A number of parties submitted that the Board should set specific targets, and these targets ranged from about 0.5% to 4% of gross revenues. The recommended levels in part reflected the observed experience elsewhere. Mr. Goulding analyzed DSM spending as a percentage of gross revenue for thirteen integrated utilities and eleven distribution companies across North America. The greatest level of spending occurred at Wisconsin Power and Light, where DSM spending as a percentage of gross revenue was 3.31%. BC Hydro, in 2003, had a 2.47% spending level, while BC Fortis in the same year spent 1% of gross revenues. Hydro Quebec Distribution in the same year was down to the 0.47% level.

Enbridge recommended that distributors should spend 3% of gross revenues. Pollution Probe recommended spending up to $2.50/MWh on "customer-side of the meter" CDM programs in 2006, which represents about 3% of gross revenues. The CEEA argued for an expenditure level ranging between 0.5% and 3% of gross revenues. GEC recommended a required minimum level of CDM spending of 1% of gross revenue and a threshold level of 3% to 5% gross revenue. Schools recommended that a distributor spend between 2% and 4% of its distribution revenues on CDM in 2006, including its 3rd tranche commitment.

Hydro One stated that the Board should set a "reference funding level" based on CDM experience in Ontario and other jurisdictions, along with input from the OPA, the Independent Electricity System Operator and other stakeholders. Energy Probe submitted that because there will be substantial CDM activity in 2006 due to 3rd tranche programs, the Board should not set a specific requirement for spending. Energy Probe and the PWU recommended that the Board should allow each distributor to determine its CDM budget level according to its own circumstance. VECC recommended that the Board place limits on total expenditures per MWh of projected energy distributed over the 2006-2010 period with budgets based on avoided cost and Rate Impact Measure (RIM) Test. VECC suggested that the RIM test be applied in addition to the TRC test to determine the rate impact of the overall CDM expenditures at rate class or sectoral level.

Conclusions

Most parties submitted that there should be no mandatory minimum expenditure target. The Board agrees that mandating spending is not appropriate, as distributors have already made commitments for a three-year period. However, the question remains whether there should be a range of permissible spending above that commitment and whether that level should be defined.

It is difficult to define with precision the optimum level of spending on CDM. The starting point in this discussion is the government's commitment to "reduce peak electricity demand growth in Ontario by five percent by 2007"[2]. By any analysis, that is a very ambitious goal. Until recently, there was minimal spending on conservation activities in the Ontario electricity sector. The Board recognizes the importance of conservation. Even a reduction in consumption of 1% offers important cost savings. High commodity costs in this sector are driven by peak demands. At peak, the cost of purchasing electricity increases dramatically. To the extent that peaks can be reduced, significant savings should result.

Whatever the level of spending, it is important that any spending over 3rd tranche levels be approved on the basis of more stringent testing of costs and benefits. This is in line with the Board's legislated objective in this area, which is "to promote economic efficiency and cost effectiveness in the ...demand management of electricity..." The Board is committed to providing a Conservation Manual that will define the cost benefit test and include the input assumptions related to energy savings for different programs and the avoided costs or value of the reduced consumption.

The other consideration in setting expenditure targets is rate impact. In the long run, if the CDM programs result in reduced consumption and cost savings, the total amount of the customer's bill should decrease. This will be the case even in the situation where there is a shareholder incentive mechanism. In the short term, however, costs will be incurred and may increase rates to customers. The benefits from CDM spending will accrue to customers over time.

The Board concludes that it is appropriate for Ontario's distributors to continue with their existing commitments, but that a specific target for 2006 is not appropriate. A distributor may apply for approval of additional spending (above the 3rd tranche) as part of its 2006 distribution rate applications, but this spending must meet the Total Resource Cost test established in the Board's Conservation Manual.

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[2] Ontario Ministry of Energy News Release. McGuinty Government Appoints Ontario's First Chief Energy Conservation Officer - Peter Love To Help Build A Conservation Culture Across Ontario. 20 April, 2005.

Lost revenue protection

The two major issues regarding distributor involvement in CDM are the need for protection for lost revenues (a lost revenue adjustment mechanism or "LRAM") and the need for shareholder incentives (a shared savings mechanism or "SSM").

Generally, there was little opposition to a lost revenue adjustment mechanism or LRAM. Most parties conceded that effective CDM programs would have the effect of penalizing the distributor because the programs will reduce revenues. The question is then the identification of the appropriate methodology for calculating an LRAM for 2006. This may depend on whether rates are established on a historical test year or a future year basis.

The basic debate with respect to revenue protection is whether the adjustment should be done in a prospective or retrospective manner. A prospective surcharge mechanism recovers lost revenues for the current year's CDM activities. In other words, the lost revenues are recovered in the same period as the distributor incurs these losses. A retrospective surcharge, on the other hand, is designed to recover revenues lost from CDM activities in a previous year. In general, the distributors preferred a prospective adjustment; however, many parties recognized that as a practical matter in 2006, the only feasible approach given the rates filing timeline would be to make an after the fact adjustment based on actual experience (a retrospective adjustment).

Mr. Goulding noted that the most common LRAM used to compensate for lost revenue is a deferral account. In any given year, the distributor calculates the demand (kW) or energy (KWh) lost due to its CDM initiatives. Differences from the forecast revenues are recovered through the deferral account, which the distributor can claim from ratepayers at a later date. The deferral account will affect the distributor's cash flow, as lost revenues will not be recovered until the next regulatory cycle.

Some parties, such as Energy Probe, argued that an LRAM is not needed. They argued that rather than introduce a second best solution, it is better to correct the rate design directly and move towards a flat monthly connection charge per customer. The strongest proponent for a fixed distribution charge was Woodstock Hydro. Woodstock Hydro argued that calculating an LRAM for 90 distributors would represent a huge regulatory burden. It also argued that the costs associated with this exercise will be substantial and must come from either the CDM budget or the distributor's customers.

Conclusions

In its December 2004 Decision RP-2004-0203, the Board concluded that an LRAM was appropriate and that it should apply to 3rd tranche expenditures. The Board indicated, at that time, that the LRAM formula would be established as part of the 2006 proceeding.

The Board continues to believe that an LRAM is appropriate and concludes that it will be retrospective, not prospective. At this time, greater accuracy will be achieved if the LRAM is calculated after the fact based on actual results.

Accordingly, a distributor will be expected to calculate the energy savings by customer class and to value those energy savings by the Board-approved distribution charge appropriate to that class. The resulting amount may be claimed in a subsequent rate year as compensation for lost revenue. As in the case of the gas distributors, the Board will continue the practice of allowing distributors to establish deferral accounts to record these expenses. As a result, no claims for lost revenue should be made as part of the 2006 rate applications.

The Board does not believe that it would be appropriate at this point to move to a fixed distribution charge. While this approach might reduce the costs associated with calculating an LRAM, the Board does not believe that those costs will be onerous. Moreover, moving to a fixed distribution charge would raise additional issues, including cost allocation issues, which cannot be addressed at this time.

Shareholder incentives

The importance of a shareholder incentive is more controversial than a lost revenue adjustment mechanism. The logic is that the distributors are driven by profits and energy conservation initiatives must compete with other activities within the distributor. If conservation is not a profit centre, but merely a cost centre, it is argued that conservation will receive less attention and investment.

A subsidiary issue is whether an incentive is necessary for conservation investments that go into rate base since, in that situation, a rate of return is automatically provided.

It was a Pollution Probe Motion that led to the Board's RP-2004-0203 Decision which permitted Ontario distributors to apply for an SSM incentive equal to 5% of net savings created by customer-side of the meter CDM expenditures in 2005 as calculated by the TRC test.

Pollution Probe made reference to the success of the conservation programs at Enbridge, which are supported by both an LRAM and an SSM. Pollution Probe estimated that over a number of years Enbridge conservation programs have reduced customers' bills by $785 million net of all costs. In addition, Pollution Probe submitted that the Enbridge ratio of bill savings to distributor expenditures of 7 to 1 is dramatically higher than the estimated bill savings to utility expenditures ratio of 2 to 1 for many US electric utilities.

Few customer groups supported the establishment of a specific CDM shareholder incentive. CCC recommended that the OPA, in conjunction with the Ontario Government, should determine whether ratepayer funds should be used to provide shareholder incentives for municipally owned distributors and that, in the absence of public policy direction supporting shareholder incentives, the Board should not provide for an incentive mechanism in 2006. AMPCO and CME also did not support the use of incentives for 3rd tranche or 2006 programs. Schools and VECC bother supported incentive payments tied to performance.

Environmental groups recommended the use of an incentive mechanism. CEEA recommended that the Board offer distributors the option of applying for a shareholder incentive. GEC recommended that all customer side program expenditures should be eligible for the incentive, including those that are capitalized.

Distributors indicated they would welcome a shareholder incentive, provided the regulatory burden was not onerous. The EDA recommended that incentives should be tied to the savings created by CDM programs, in order to encourage distributors to make their best efforts in creating and delivering CDM programs. Enbridge commented that an incentive is needed to acknowledge that CDM is a different form of business activity than distributing electricity and that it requires much more time and effort from distributors.

Hydro One submitted that both utility-side expenditures and customer-side expenditures should be eligible for an incentive because both have the same value to the electricity system in terms of reducing peaks. Hydro One noted that utility-side investments / expenditures should be limited to those that are incremental, solely focused on CDM, and would otherwise not be undertaken without a particular incentive.

Those parties that supported creation of shareholder incentives offered varied views on what form might be appropriate. There was also debate regarding the level of complexity of a shareholder incentive.

Pollution Probe and GEC recommended that the Board extend the fiscal year 2005 SSM (which provides shareholders with 5% of the TRC net benefits) to 2006.

CEEA supported an SSM incentive that equals 5% of TRC net benefits as proposed by Pollution Probe, but indicated that an incentive based on kWhs savings would also be acceptable. The CEEA suggested that an incentive of $0.0025/kWh would have a similar effect as 5% of TRC net benefits (based on a 'typical' delivered cost of electricity of $0.10 /kWh × 5% ÷ a typical benefit cost ratio for electric CDM of 2). PWU supported this approach. Pollution Probe objected to this approach. Pollution Probe claimed that it would be inconsistent with the Board's objective to promote cost effectiveness. In its view, an incentive based on kWh savings will not motivate the distributors to implement CDM programs which will maximize bill savings because there will be no distinction between peak and off-peak savings. CCC also took the position that the incentive should be based on TRC results.

Enbridge stated that an incentive mechanism is necessary and that the TRC is the appropriate metric for measuring conservation benefits and determining the incentive. In particular, it noted that the TRC approach is consistent with the shared savings mechanisms, as they have been applied around North America and creates a natural incentive for dsitributors to minimize program administration costs.

Schools suggested that there should be some threshold for performance and that the 5% incentive should not be applied to amounts below that threshold. VECC proposed a sliding scale approach that would reward superior performances. Others objected to these types of approach as being unnecessarily complicated. GEC took the position that in future years the Board should consider adjusting the SSM to require higher performance levels.

Conclusions

The Board, in its RP-2004-0203 Decision, found that a distributor shareholder incentive was an appropriate way to encourage distributors to pursue CDM programs. The Board continues to be of this view. Distributors should be rewarded with 5% of the net savings established by the TRC test. The Board recognizes that it will be essential to establish certain inputs and to define avoided costs. Accordingly, the Board's Conservation Manual will address these matters. This will allow parties to screen CDM programs and calculate the relevant incentives.

The Board notes the views of some parties that this formula could be more sophisticated and include the establishment of thresholds to encourage superior performance. The Board believes that during this transitional period it is best to use a simple mechanism and defer consideration of more complex methodologies to later years.

The SSM will apply to TRC benefits achieved by 3rd tranche expenditures as well as any incremental expenditures that are approved in 2006. However, as in the case of the Board's Decision with respect to 2005, the incentive will not apply to utility-side activities. Because the SSM will be retrospective, no claims for a shareholder incentive should be made in the 2006 rate applications.

There has been considerable discussion in this proceeding as to whether CDM expenditures on the utility side should be differentiated from customer-side expenditures. The Board recognizes that conservation programs should have a balance between the two. It is important to recall however, the Board's earlier finding that the SSM incentive does not apply to utility-side investments. The Board previously ruled with respect to the 2005 SSM that the inclusion of capitalised assets into rate base provides sufficient incentives. The Board continues to hold that view.

Treatment of expenditures

CDM expenditures can be either capital or operating expenditures. In some cases, both will be associated with specific programs. The question then becomes: should these expenditures be expensed, amortized, included in rate base or some combination?

In the case of amortization, the question becomes over what term. Some parties such as AMPCO argued that CDM investment should be amortized over the expected life of the program. CCC supported this approach. One difficulty with this argument is that it requires an assessment of each program, which may become a complex task.

Mr. Goulding pointed out that the choice between expensing and amortizing CDM expenditures will affect rates. Where a distributor expenses CDM costs, they are immediately reflected in rates. On the other hand, where a distributor decides to capitalize costs, the costs will not affect rates as dramatically. Mr. Goulding reviewed the experience of utilities across North America. He noted for example, that the BC Utilities Commission requires BC Fortis to capitalize all CDM expenditures and amortize them at a straight-line rate of 12.5%. In the Ontario gas industry, the practice has been to approve an operating budget for CDM spending to be treated as both capital and expense, depending on the nature of the expenditure.

The PWU submitted that, as with all distributor investments, CDM capital investment should be reflected in rate base. The CEEA recommended that the customer-side of the meter CDM spending be expensed and utility-side of investment be treated in the ordinary course of accounting. Schools stated that operating costs of CDM programs such as managing the program should be expensed in the same manner as other operating costs.

CEEA submitted that there are not overwhelming reasons to favour one approach over another. It suggested that the Board adopt a policy of capitalization on a simplified assumption that a five-year average period should be used for amortization.

Conclusions

The Board concludes that CDM expenditures that relate to operating expenses should be expensed in the year they are incurred, and CDM expenses that relate to capital should be capitalized. The amortization rate for capital items should be the usual rate for the nature of the item, as set out in Appendix B of the Handbook.

Distribution line losses

The draft Handbook contains two alternative rate making options with respect to distribution line losses as they relate to CDM. Alternative 1 is the status quo, where line losses are passed through and the a distributors has no financial incentive to reduce line losses. Under Alternative 2, any variance between a distributor's actual electricity purchases and sales is no longer a pass through item. As a consequence, if Alternative 2 is adopted, distributors will have a direct financial incentive to reduce line losses.

Pollution Probe argued that the Board should adopt Alternative 2, as it will make Ontario more energy efficient. They agreed however, that a distributor should be permitted to make rate base capital expenditures to reduce its line losses.

Mr. White testified that Alternative 2 would penalize distributors because line losses increase due to factors outside of a distributor's control. Examples include the potential impact arising from large volume customers or electricity generators being added or removed from the distribution system. He did acknowledge that the technology exists to reduce line losses and that if this technology is applied appropriately, predictable loss reductions will result.

Conclusions

Reducing line losses is an opportunity for conservation in this Province. The Board estimates that a 25% reduction in line losses could have a value of approximately $120 million to ratepayers.

Currently, distributors have a limited incentive to reduce these losses. The Board acknowledges that to some extent line losses are beyond the control of distributors. However, the Board does expect a distributor to take action where losses can be reduced. It is therefore appropriate for distributors to have an incentive to do so.

The Board concludes, however, that it is not feasible to introduce a financial incentive in 2006 rates related to distribution line loss reduction. The RSVAs currently capture in a combined fashion variances from a variety of sources, including price differences, quantity differences, timing differences and billing errors. The Board has concluded that distribution line loss variances will be difficult to isolate and quantify with precision.

The Board has therefore concluded that 2006 will focus on identifying those distributors with high average losses and requiring them to report on those losses and provide an action plan as to how the distributor intends to reduce the level of losses. Any distributor whose 3-year average of distribution losses is higher than 5% will be required to make this report. Appendix 1 to this Report sets out the 2003 distribution line loss data for distributors.

The Board intends to address the accounting issue discussed above with a view to implementing a financial incentive mechanism in due course. The Board also intends to initiate a study in the near future that will examine losses in Ontario as well as the approaches taken in other jurisdictions. The intention will be to refine the Board's approach and the incentive structure in future proceedings.

Cost allocation

AMPCO and CME recommended that the costs of the CDM programs should be recorded at class levels for cost allocation in order that CDM program costs are recovered from the appropriate class. There is a general view that most CDM expenditures relate to residential and commercial customers. The view is that large industrial customers require customer specific programs that are unlikely to be within the expertise of the distributors and that there is a strong likelihood that industrial customers have already instituted energy saving programs.

Other parties did not oppose, to any significant degree, the principle that costs should be allocated to benefiting customer classes. There will be, however, some costs that cannot be allocated directly. Indirect costs will have to be allocated across customer classes on some other basis, such as the level of consumption or number of customers.

Conclusions

The Board concludes that direct CDM operating expenses should be allocated by participant customer class. Indirect operating expenses and capital expenditures, including amortization, should be allocated across all customer classes. Both allocations are on a volumetric basis.

Audits and reporting

A number of the experts provided testimony as to how the CDM programs should be audited and by whom. A number of parties suggested that the distributor should be able to hire its own auditor. Others took the position that the Board should conduct the audits.

Conclusions

The Board recognizes there are advantages to both approaches. In the end, it seems logical to allow the distributor, at least in the first instance, to file its own audit. Each distributor varies in size and in the nature of operations. They all have access to auditors who are competent to check the calculations used for the purpose of the TRC, the LRAM, and the SSM calculations. Audits will be limited to ensuring the inputs from the Board, avoided costs from Hydro One and participation data from the distributors are accurately reported. The Board recognizes that its oversight will continue. It is important that the distributors understand the importance of an independent audit.

With respect to reporting, the Board has concluded that those CDM expenditures, which are approved using the TRC test, will not require quarterly reports, but will require an Annual Report. The format of an Annual Report will be contained in the Conservation Manual. This Annual Report will be in the same format as the Annual Report to be used with respect to 3rd tranche expenditures.

Appendix 1: Ontario Distributors' Consumption and Distribution Line Losses for 2003

Data as Reported by LDCs as part of 2003 RRR

Utility	Wholesale kWh Bought	Total kWh Sold	Distribution losses kWh	Distribution Losses % of Wholesale kWh Bought (Calculated)	Distribution Revenue	Total Electricity Revenue	Total Customers
Atikokan Hydro Inc.	43,095,892	41,470,813	1,625,079	3.77%	$757,771	$3,332,923	1,767
Aurora Hydro Connections Limited	440,285,392	400,449,564	39,835,828	9.05%	$5,899,605	$33,294,049	18,607
Barrie Hydro Distribution Inc.	1,432,453,894	1,364,950,528	67,503,366	4.71%	$25,489,357	$10,411,911	61,597
Bluewater Power Distribution Corporation	1,077,902,124	1,027,053,267	50,848,857	4.72%	$13,685,822	$81,161,496	44,082
Brantford Power Inc.	947,689,830	913,537,128	32,471,288	3.43%	$10,995,805	$73,449,133	43,590
Burlington Hydro Inc.	1,691,966,521	1,621,983,270	69,370,627	4.10%	$24,521,862	$135,727,642	56,867
Cambridge and North Dumfries Hydro Inc.	1,523,715,993	1,457,949,580	65,766,413	4.32%	$17,708,002	$121,201,000	45,772
Centre Wellington Hydro Ltd.	151,458,894	150,692,337	766,557	0.51%	$2,426,695	$8,104,397	5,848
Chapleau Public Utilities Corporation	34,764,471	33,611,224	1,153,247	3.32%	$533,375	$2,570,739	1,374
Chatham-Kent Hydro Inc.	893,653,654	856,024,065	37,629,589	4.21%	$11,474,381	$71,765,494	31,923
Collus Power Corp.	376,054,075	364,621,938	11,281,622	3.00%	$3,743,330	$30,228,632	13,400
Cooperative Hydro Embrun Inc.	28,452,754	26,954,399	1,498,355	5.27%	$446,551	$2,059,874	1,602
E.L.K. Energy Inc.	193,922,997	188,820,788	5,102,209	2.63%	$5,097,928	$17,622,474	10,266
Enersource Hydro Mississauga Inc.	7,835,477,880	7,593,570,208	241,907,672	3.09%	$88,485,579	$627,954,000	173,863
EnWin Powerlines Ltd.	2,786,643,064	2,713,656,506	72,986,558	2.62%	$37,677,400	$221,281,192	82,530
Erie Thames Powerlines Corporation	361,049,074	356,532,942	4,516,133	1.25%	$4,841,754	$30,100,625	13,709
Espanola Regional Hydro Distribution Corporation	65,219,195	64,447,371	771,824	1.18%	$1,008,673	$4,892,233	3,325
Festival Hydro Inc.	637,470,787	624,951,824	12,518,963	1.96%	$8,115,253	$51,014,534	18,911
Fort Albany Power Corporation	8,744,481	8,262,153	482,328	5.52%	$602,532	$1,124,160	300
Fort Frances Power Corporation	83,865,020	78,847,143	5,017,877	5.98%	$1,118,571	$5,366,867	3,788
Grand Valley Energy Inc.	10,230,741	9,959,883	270,858	2.65%	$176,169	$847,075	673

Note: Includes LDCs reporting complete and reliable data sets

Prepared without Audit from Information Provided by LDCs.
Regulatory Audit Department, March 2005

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Utility	Wholesale kWh Bought	Total kWh Sold	Distribution losses kWh	Distribution Losses % of Wholesale kWh Bought (Calculated)	Distribution Revenue	Total Electricity Revenue	Total Customers
Great Lakes Power Limited	214,830,959	196,493,988	18,336,971	8.54%	$2,892,000	$25,542,000	11,475
Greater Sudbury Hydro Inc.	921,461,138	876,493,834	44,967,303	4.88%	$15,873,605	$71,725,811	82,854
Guelph Hydro Electric Systems Inc.	1,492,595,642	1,464,302,137	28,293,505	1.90%	$20,022,000	$1,574,703	42,979
Haldimand County Hydro Inc.	377,383,766	352,419,236	24,964,530	6.62%	$7,226,884	$25,746,833	20,890
Halton Hills Hydro Inc.	462,324,178	437,845,875	24,478,303	5.29%	$7,752,651	$37,362,382	22,350
Hearst Power Distribution Company Limited	116,654,368	113,544,532	3,109,836	2.67%	$591,636	$8,298,179	2,780
Hydro 2000 Inc.	28,326,781	26,545,865	1,780,915	6.29%	$326,277	$2,053,402	1,123
Hydro Hawkesbury Inc.	214,289,172	204,639,435	9,649,738	4.50%	$1,096,345	$15,595,350	5,238
Hydro One Brampton Networks Inc.	3,438,532,293	3,340,507,834	98,024,459	2.85%	$52,399,000	$280,205,000	103,205
Hydro One Networks Inc.	24,479,000,000	22,807,750,000	1,671,250,000	6.83%	$612,000,000	$2,415,000,000	1,132,899
Hydro Ottawa Limited	7,755,187,001	7,483,288,362	271,898,675	3.51%	$89,680,000	$588,100,000	269,205
Hydro Vaughan Distribution Inc.	2,844,252,992	2,756,870,098	87,382,894	3.07%	$59,640,000	$269,880,000	71,908
Innisfil Hydro Distribution Systems Limited	234,480,796	218,234,486	16,246,310	6.93%	$5,576,102	$19,726,747	15,666
Kenora Hydro Electricity Corporation Ltd.	114,266,361	107,599,752	6,666,609	5.83%	$1,580,707	$7,930,873	6,064
Kingston Electricity Distribution Limited	750,815,050	728,977,266	21,837,784	2.91%	$8,551,327	$44,835,879	26,359
Kitchener-Wilmot Hydro Inc.	2,023,071,898	1,985,904,757	37,167,141	1.84%	$29,782,692	$158,669,026	74,347
Lakefront Utilities Inc.	289,976,577	277,498,686	12,477,891	4.30%	$3,510,968	$21,274,641	8,589
Lakeland Power Distribution Ltd.	233,579,800	229,178,690	4,401,110	1.88%	$4,396,933	$18,742,789	8,926
Markham Hydro Distribution Inc.	2,118,362,138	2,051,799,185	66,562,953	3.14%	$48,491,000	$214,937,000	72,313
Middlesex Power Distribution Corporation	169,452,219	161,448,059	8,004,160	4.72%	$1,798,908	$12,972,609	6,702
Midland Power Utility Corporation	239,348,504	230,580,764	8,767,740	3.66%	$2,346,818	$18,148,687	6,372

Note: Includes LDCs reporting complete and reliable data sets

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Utility	Wholesale kWh Bought	Total kWh Sold	Distribution losses kWh	Distribution Losses % of Wholesale kWh Bought (Calculated)	Distribution Revenue	Total Electricity Revenue	Total Customers
Milton Hydro Distribution Inc.	602,790,672	585,195,347	18,611,920	3.09%	$8,004,346	$49,128,514	20,934
Newmarket Hydro Limited	659,301,476	636,823,652	22,477,824	3.41%	$11,470,258	$54,858,396	24,327
Niagara Falls Hydro Inc.	802,834,107	765,481,597	39,958,139	4.98%	$13,997,678	$67,323,134	42,783
Niagara-on-the-Lake Hydro Inc.	174,477,589	167,511,648	6,965,941	3.99%	$3,100,961	$14,521,217	7,068
Norfolk Power Distribution Inc.	370,302,865	351,367,276	18,935,589	5.11%	$7,107,499	$32,553,460	17,638
North Bay Hydro Distribution Limited	587,699,134	564,366,532	23,332,602	3.97%	$8,902,384	$57,936,687	29,957
Northern Ontario Wires Inc.	146,069,796	140,645,421	5,424,375	3.71%	$2,081,087	$11,122,750	6,328
Oakville Hydro-Electric Distribution Inc.	1,685,424,271	1,611,802,942	73,621,329	4.37%	$25,322,000	$135,525,512	51,842
Orangeville Hydro Limited	237,476,511	231,211,798	6,264,713	2.64%	$3,839,390	$18,704,515	9,635
Orillia Power Distribution Corporation	326,759,000	314,306,000	12,416,842	3.80%	$6,979,000	$25,312,000	12,270
Ottawa River Power Corporation	210,360,355	205,451,211	4,909,144	2.33%	$3,637,558	$16,687,169	12,889
Peninsula West Utilities Limited	346,108,353	329,678,374	16,429,979	4.75%	$6,325,417	$29,504,574	18,316
Peterborough Distribution Inc.	778,756,793	762,746,952	16,009,841	2.06%	$12,555,083	$60,083,077	30,973
PUC Distribution Inc.	755,126,020	718,340,073	36,785,947	4.87%	$11,849,518	$53,033,866	32,449
Renfrew Hydro Inc.	95,886,661	90,960,035	4,926,626	5.14%	$1,330,792	$7,427,790	4,050
Richmond Hill Hydro Inc.	1,064,420,003	1,025,416,582	39,003,421	3.66%	$23,821,512	$86,981,019	46,073
Rideau St. Lawrence Distribution Inc.	136,093,779	126,652,017	9,441,762	6.94%	$1,546,288	$10,158,256	5,750
Scugog Hydro Energy Corporation	53,266,843	49,804,635	3,462,345	6.50%	$503,041	$3,891,988	2,957
Sioux Lookout Hydro Inc.	98,114,759	92,440,646	5,674,113	5.78%	$1,317,578	$7,068,604	2,736
St. Catharines Hydro Utility Services Inc.	1,364,300,470	1,324,735,765	39,564,714	2.90%	$17,112,718	$106,156,470	66,968
St. Thomas Energy Inc.	359,240,700	358,502,792	737,908	0.21%	$5,345,216	$30,270,202	14,614

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Data as Reported by LDCs as part of 2003 RRR

Utility	Wholesale kWh Bought	Total kWh Sold	Distribution losses kWh	Distribution Losses % of Wholesale kWh Bought (Calculated)	Distribution Revenue	Total Electricity Revenue	Total Customers
Tay Hydro Electric Distribution Company Inc.	46,278,450	42,437,552	3,841,111	8.30%	$1,231,240	$3,919,043	3,938
Terrace Bay Superior Wires Inc.	20,358,352	19,751,725	606,627	2.98%	$396,629	$1,594,472	951
Thunder Bay Hydro Electricity Distribution Inc.	1,094,232,705	1,052,389,834	41,842,871	3.82%	$14,606,646	$78,339,527	49,373
Toronto Hydro-Electric System Limited	26,824,037,218	25,873,335,727	950,701,491	3.54%	$432,765,001	$2,389,949,000	668,626
Veridian Connections Inc.	2,371,164,865	2,262,794,351	108,370,514	4.57%	$32,469,678	$168,329,147	91,164
Wasaga Distribution Inc.	103,374,882	97,838,571	5,536,311	5.36%	$2,536,911	$8,622,740	11,810
Waterloo North Hydro Inc.	1,277,829,812	1,222,390,968	55,438,844	4.34%	$21,623,743	$105,874,316	45,490
Welland Hydro-Electric System Corp.	509,954,013	479,320,612	30,633,401	6.01%	$4,875,211	$37,904,720	30,659
Wellington Electric Distribution Company Inc.	15,540,160	14,608,310	940,850	6.05%	$420,000	$1,628,000	1,287
Wellington North Power Inc.	95,369,137	94,335,840	1,033,297	1.08%	$1,058,460	$7,327,230	3,343
West Coast Huron Energy Inc.	93,396,711	92,514,860	881,850	0.94%	$1,464,850	$8,042,126	3,750
West Nipissing Energy Services Ltd.	65,968,206	64,559,957	593,714	0.90%	$957,144	$3,744,678	3,103
West Perth Power Inc.	70,774,591	67,094,312	3,680,279	5.20%	$680,490	$35,697,690	2,609
Westario Power Inc.	457,320,681	441,285,680	16,006,224	3.50%	$6,950,294	$35,619,687	20,399
Woodstock Hydro Services Inc.	414,235,826	404,128,227	7,448,482	1.80%	$5,167,636	$32,120,677	13,866
Total	113,456,963,132	108,632,497,592	4,822,105,018	4.25%	$1,943,693,526	$9,588,794,614	4,036,963
			Average Utility Distribution Loss	4.00%			

Note: Includes LDCs reporting complete and reliable data sets

Prepared without Audit from Information Provided by LDCs
Regulatory Audit Department, March 2005